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Oil Shale Industry

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This document contains information used as the basis for deciding if New Source Performance Standards or National Emissions Standards for Hazardous Air Pollutants are necessary for the oil shale industry. This document includes an industry description, an analysis of potential emissions, and a compilation of potential emission control techniques.

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1. INTRODUCTION

1.1 SCOPE

This Source Category Survey Report (SCSR) describes the existing oil shale industry and its probable future, identifies and evaluates emission sources, and identifies and compares available pollution control techniques.

For this report, the oil shale industry includes shale mining, shale transportation, onsite conversion of kerogen in shale to unrefined shale oil, off-gas processing, and onsite use of product gas or process heat for steam generation. Onsite conversion includes hydrotreating to upgrade oil to a pipeline product. As described in Chapter 4, some shale oil conversion processes combine these steps.

1.2 INDUSTRY DESCRIPTION

Because no commercial-scale oil shale recovery facility is currently operating, this report is based on pilot-plant, bench-scale, and material-balance data scaled-up to approximate commercial operations. Accuracy of these data will not be known for approximately 2 years, during which time commercial-scale facilities are scheduled to begin operation. Testing and evaluation of these facilities may yield hard data for standards development. In the absence of hard data, this report provides a best estimate of commercial-scale oil shale recovery operations.

The United States has large oil shale reserves. Estimates range around 270 billion megagrams (Mg) (298 billion tons), which could yield 2 trillion barrels of oil. This amount would supply the United States for 168 years at the 1978 consumption rate. About 90 percent of these reserves are concentrated in Colorado, Utah, and Wyoming. Other States with promising deposits are Michigan, Kentucky, Tennessee, and Oklahoma.

Oil shales are rocks that contain kerogen as a primary organic constituent, but they may contain natural bitumin and, in some instances,

small amounts of crude oil. Kerogen is extracted by heating oil shale to about 400° C (750° F) and thermally degrading (pyrolyzing) the organic matter. Shale oil is recovered when this gas is condensed. Preliminary treatment--hydrogenation--upgrades the oil to a pipeline product.

Thermal decomposition is conducted in a retort, of which there are two generic categories--surface and in situ. Basic steps for surface retorting include mining, crushing, transporting, retorting, and spent shale disposal. Some mining may be necessary for in situ retorting, but most retorting occurs underground in the shale deposit, with spent shale remaining in the retort.

Surface retorts use either direct-heat or indirect-heat transfer for pyrolysis of shale kerogen. Direct-heat units are heated by internal combustion of recycle gases and residual carbon on spent shale. Indirect-heat units use a gas or solid heated outside the retort. Some processes have been designed to use a combination of direct- and indirect-heat.

There are two types of in situ retorts: true in situ (TIS) and modified in situ (MIS). TIS involves well drilling, rock fracturing, and retorting within rock formations. MIS involves mining and removing from formations 15 to 40 percent of the ore before rubbling and in situ retorting. Partial removal allows more complete rubbling of remaining shale and greater oil recovery. Shale removed from in situ retorts is processed aboveground.

1.3 EMISSION SOURCES

Based on estimates approximated from existing pilot-plant and bench-scale data, four main emission sources are possible in the oil shale recovery process: mining, processing, retorting, and spent shale disposal. Product gas processing, onsite use of product gas or process heat, and upgrading of shale oil to a pipeline product are also potential emission sources.

Mining activities associated with aboveground oil shale retorting are expected to be the largest in the world. Mining's potential atmospheric pollution sources include excavation, blasting, transportation, and equipment movement. Processing of mined oil shale includes size reduction (crushing) for retorting and conveyer transportation of crushed shale. Primary pollutants from mining and processing are particulate matter. In addition,

gaseous pollutants from blasting and equipment usage will be significant for commercial-scale operations.

A major source of air pollution is shale retorting, which produces sulfur compounds, nitrogen oxide, particulate matter, hydrocarbons, carbon monoxide, and trace elements. Except for leaks, these pollutants are not released during the actual retorting process but during processing of oil and gas products. As noted earlier, most available air pollution data are from pilot-plant and semi-works facilities; no commercial-scale facilities exist. The amount and characterization of these pollutants cannot be completely assessed until a commercial-scale facility is complete.

Spent shale disposal is also an emission source. Particulate matter and hydrocarbon emissions can occur during transfer, handling, and disposal. Trace elements also have high potential of accompanying these emissions.

Combustion of retort off-gas to generate electricity or provide process heat can result in emissions of all criteria pollutants, hazardous pollutants, and trace elements. Of the criteria pollutants, sulfur oxides have the highest pollution potential, because of the high predicted sulfur content of retort off-gas. Complete characterization and quantification of hazardous pollutant and trace element emissions will require generation of additional emissions data.

Pollutants of primary concern in oil shale processing are particulate matter, sulfur dioxide, nitrogen oxides, hydrocarbons, and carbon monoxide. Subpart D, 40 CFR 60, can be interpreted as applicable to combustion of product gas in steam-generating units of 43 megawatts (MW) or greater. Product gas use in other industrial-type boilers will probably be covered under New Source Performance Standards (NSPS) being developed for industrial boilers. Additional data will help determine applicability of these standards to use of product gas at oil shale production facilities.

1.4 POTENTIAL CONTROL TECHNOLOGY

Control technology for emissions of particulate matter, sulfur, nitrogen oxides, hydrocarbons, and carbon monoxide is described fully in Chapter 6. This section summarizes that presentation.

Control technology for particulate matter includes mechanical (dry) and wet collectors. Mechanical collectors include fabric filters, electrostatic

precipitators, and cyclones. Wet collectors include venturi scrubbers, electrostatic precipitators, wet suppression, spray towers, cyclone scrubbers, and impingement-plate scrubbers.

Two options for controlling sulfur emissions from oil shale processing are sulfur removal from stack gas and sulfur removal from fuel. The first method, commonly called flue gas desulfurization (FGD), depends on retort gas sulfur species' being converted to sulfur dioxide during combustion. Because it requires this conversion, FGD is applicable only when retort gas is combusted. In oil shale operations, retort gas combustion is used to create heat or steam.

Techniques for removing retort gas sulfur compounds prior to combustion include a number of processes, outlined in Chapter 6, for direct and indirect conversion (acid gas removal). These removal processes are not limited by where the gas is used.

Options available for reducing potential nitrogen oxide emissions are combustion modification, fuel-nitrogen removal, and stack gas removal of nitrogen. Nitrogen must be converted to nitrogen oxide for stack gas removal. Combustion system modifications may not allow oil shale facilities to meet nitrogen oxide emissions standards, but retrofit control systems can be added to help meet them. For off-site use of product gas, nitrogen must be removed in a chemically reduced form prior to combustion or stack gas removal must be accomplished at the combustion site.

There are four techniques for controlling hydrocarbon and carbon monoxide emissions: (1) more complete process equipment sealing, (2) more complete fuel combustion, (3) use of catalytic converters, and (4) use of thermal oxidizers. The first of these involves inspection and maintenance of superior process equipment seals; the second is accomplished by adjustments to the combustion process. The last two techniques are for removing hydrocarbon from process streams.

1.5 REVIEW OF STATE REGULATIONS

The three States with major oil shale development activity are Colorado, Utah, and Wyoming. Several other States expect development activity in the near future. Table 1-1 presents the status of U.S. Environmental Protection Agency (EPA) delegations of permit regulations in Colorado, Utah, and Wyoming.

TABLE 1-1. STATUS OF EPA PERMIT DELEGATIONS TO STATES WITH OIL SHALE DEVELOPMENT ACTIVITY

Permit type	Delegation status		
	Colorado	Utah	Wyoming
National pollution discharge elimination system (NPDES)	Yes	No	Yes
Drinking water	No	No	No
Hazardous waste	No	No	No
Construction grants	Yes	Yes	Yes
Dredge and fill permit (Section 404)	No	No	No
National Emission Standards for Hazardous Air Pollutants (NESHAP)	Partial	Yes	No
Noise	No	No	No
Radiation	No	No	No
Prevention of Significant Deterioration (PSD)	No	No	Yes

Each of these regulations has potential to influence further oil shale development. Each of these three major States is presently writing specific regulations for oil shale processing.

Several other Colorado State regulations may affect oil shale development. Opacity regulations restrict emissions obscuring vision in excess of 20 percent. For particulate matter, current regulations allow no more than 0.5 lb/10^6 Btu input for units generating not more than 10^6 Btu per hour and 0.1 lb/10^6 Btu input for units generating 500 x 10^6 Btu input per hour or more. Sulfur dioxide regulations are specific for oil shale operations, with no standard for operations producing less than 1,000 barrels per day. For operations of 1,000 barrels per day or more, the standard is 0.3 lb SO_2/bbl processed for the sum of all sulfur dioxide emissions from a given production facility. This standard also applies to oil refining from shale. The sulfur dioxide standard for all new oil-fired operations is 0.8 lb $SO_2/10^6$ Btu input if the process is less than 250 x 10^6 Btu/hr and 0.3 lb $SO_2/10^6$ Btu input for operations of 250 x 10^6 Btu/hr or greater. It is not known if the standards for oil-fired operations would apply to facilities producing less than 1,000 barrels per day. The nitrogen oxide regulation in Colorado is 0.30 lb $NO_x/10^6$ Btu input for liquid fuels. Standards for three metals--beryllium, mercury, and lead--may also be applicable, allowing emissions of 10g Be/24 hr, 2,300 g Hg/24 hr, and 1.5 µg Pb/m^3 (averaged over a 1-month period), respectively.

Two Utah State regulations may also affect oil shale development. Plumes from existing facilities can have densities no darker than 20 percent opacity. Oil-fired operations may only use oil containing 1 percent sulfur, by weight, or less.

Wyoming's standards for sulfur dioxide emissions from oil burning equipment limit emissions to 0.8 lb/10^6 Btu heat input. Emissions of nitrogen oxide from new gas-fired equipment are limited to 0.20 lb/10^6 Btu.

Kentucky is presently preparing to write specific standards for oil shale operations. The existing Kentucky particulate standard for new process operations does not allow emissions with 20 percent or greater opacity. For heat exchangers, sulfur dioxide emissions are limited to 3.0 lb/$SO_2/10^6$ Btu for sources up to 10 x 10^6 Btu/hr, and 0.8 lb $SO_2/10^6$ Btu for

sources up to 250 x 10^6 Btu/hr or more. Nitrogen oxide standards limit emissions to 0.3 lb $NO_x/10^6$ Btu heat input.

Michigan standards do prohibit emissions with opacities of 20 percent or greater or with opacities of 40 percent within any 3-minute period in a 60-minute period.

Oklahoma has regulations for fuel-burning equipment prohibiting particulate matter emissions of more than 0.6 lb/10^6 Btu heat input. Also for fuel-burning equipment, sulfur dioxide emissions of 0.2 lb $SO_2/10^6$ Btu heat input and nitrogen oxide emissions of 0.2 lb $NO_x/10^6$ Btu heat input are not allowed. Tennessee regulations prohibit discharge of any air contaminant with an opacity of 20 percent or greater for more than 5 minutes in any hour. In no instance can Tennessee facilities with capacities over 1,000 x 10^6 Btu/hr emit more than 2.8 lb SO_2/hr.

2. SUMMARY

2.1 INDUSTRY DESCRIPTION

Currently, only pilot-plant or semi-works facilities exist for each basic shale oil extraction process. Considerable difference of opinion exists as to when oil extracted from shale will be competitive with other oil sources. The inability to predict potential competitiveness accurately is caused by crude oil's uncertain future availability and price and by uncertainties associated with shale oil extraction technology.

The history of shale oil production is largely undocumented. It is known that a commercial industry flourished around 1860 in Scotland but declined before 1900 because of diminished resources and cheaper crude oil. In the United States, the industry flourished in the late 1800s but declined as more crude oil became available. In the 1940s, oil shale development was subsidized by the U.S. government as a potential substitute for imported oil during World War II. Total U.S. production from pilot-plant and semi-works facilities has been small compared to total oil production. However, the oil shale industry is important to the the U.S. energy future as an alternative to imported crude oil.

2.2 STUDY OBJECTIVES

This study had several objectives, the most important of which was to determine facilities, processes, and pollutants for which a New Source Performance Standard (NSPS) or National Emission Standard for Hazardous Air Pollutants (NESHAP) may be appropriate. It has been determined that no commercial-scale oil shale production facilities exist, leaving no basis for determining application of these standards. However, commercial-scale facilities are scheduled to go on line in the next 2 years, depending on numerous economic criteria and potential environmental problems. Data obtained during construction and operation of these facilities may prove useful for standards development.

2.3 STUDY METHODOLOGY

Information used in this study was obtained from several sources, literature searches, review and journal articles, plant visits, State regulations, permit requests, and personal contacts with industry members. In addition, information was already available in several EPA publications and in draft reports of current EPA-funded studies.

3. CONCLUSIONS

3.1 TECHNOLOGY GROWTH

Penetration of shale oil into the world crude oil market will be a major force driving development schedules for facilities. Although no commercial facilities are presently in operation and none are slated to be on-line this year, two should go on-line in 1982. A timetable for commercial operation of existing projects estimates a total of 8 facilities by 1985 and 12 facilities by 1990. However, this schedule depends on the price and availability of current crude oil sources. Cost and resource requirements for oil shale are great, and investors require security. While potential for growth is great, actual growth is affected by many variables and is difficult to assess. Therefore, this timetable should be considered only an approximation. Because the most attractive oil shale deposits are located near western Class I Prevention of Significant Deterioration (PSD) areas, the currently allowable PSD increment may preclude full industry development.

Because no commercial facilities are presently operating, only pilot-plant and semi-works data were available for this study. These data must be scaled-up to approximate operations in a commercial facility and may not accurately predict potential emissions. In addition, certain features of oil shale processing systems may change when scaled-up to commercial size. Thus, without hard commercial-scale data, no solid baseline exists for standards development.

3.2 POTENTIAL PROBLEM AREAS TO STANDARDS DEVELOPMENT

Many problem areas characterized earlier still exist. First, data are limited on characterization of emissions, especially of hazardous air pollutants. It is difficult to develop standards for unknown pollutants. No commercial plants are in operation, and numerous potential problems are associated with scaling-up existing pilot-plant and semi-works emission data. Linear models for this scaleup may be inappropriate, and determining other

functional relationships is difficult. In addition, because no commercial facilities exist, there is no demonstrated control system for major process streams. Without demonstrated control technology, standards development may be burdened with demonstrating that technology can be transferred from similar industries.

3.3 RESULTS

Potential emissions from oil shale operations and their control techniques have been identified in previous sections and are discussed more completely in Chapter 5. However, many data needed for standards development are not available (see Table 3-1).

Additional monitoring of air, surface water, groundwater, solid waste disposal piles, and oil shale residual streams at a commercial facility may be needed to provide adequate date for impact calculations. Shale mining, transportation, and disposal operations may be on the largest scale ever developed and will require extensive monitoring to determine impacts fully. Retort technology needs to be demonstrated commercially to permit characterization and quantification of emissions. Tradeoffs among air, water, and solid waste impacts can then be better studied. Finally, applicability of sampling and analysis methods should be verified for oil shale pollutant streams.

3.4 REFERENCES

1. Oil Shale Briefing Book. Region VIII, U.S. Environmental Protection Agency. Denver, Colorado. October 21-23, 1980.

TABLE 3-1. DATA USUALLY COLLECTED IN SOURCE CATEGORY SURVEY

Parameter	Data status
List of facilities	Compiled
Size	Estimated[a]
Production capacity	Estimated
Products	Determined
Production rates	Estimated
Raw materials	Determined
Feasibility of testing	Determined
Type of air pollution control system	Projected[b]
System operation parameters	Estimated
System maintenance frequency	Estimated
Fugitive emissions sources	Estimated
Chemical nature of pollutants	Estimated
Rates of pollutant discharge	Estimated

[a]Estimated from pilot-plant data.
[b]Projected from known parameters of existing pollution control equipment.

4. DESCRIPTION OF THE OIL SHALE INDUSTRY

This chapter describes the oil shale source category, basic processes under development, and the oil shale industry as a whole. As stated in previous chapters, no commercial oil shale production is currently underway. Information presented in this chapter is based on pilot plants, semi-works plants, engineering estimates from plans for future facilities, and commercial-sized runs of some operations.

4.1 SOURCE CATEGORY

For this Phase I Source Category Survey Report (SCSR), the oil shale industry includes shale mining and onsite conversion of kerogen in shale to unrefined shale oil suitable for refinery processing. For some production methods, mining and conversion are combined. Additionally, onsite conversion includes hydrotreating to upgrade oil to a pipeline product.

Numerous definitions are available for oil shale. In geological terms oil shale is not a shale, but a mudrock. Two organic constituents commonly occur in mudrocks: kerogen, which can be converted to shale oil, and natural bitumin. Kerogen, of relatively high molecular weight, is a dark, grey-black, amorphous organic solid present in various quantities in mudrock. Kerogen contains from 70 to 80 percent carbon, from 7 to 11 percent hydrogen, from 10 to 15 percent oxygen, traces of nitrogen and sulfur, and traces of numerous other elements. By definition, kerogen includes hydrocarbon compounds not soluble in ordinary organic solvents, such as ether, acetone, benzene, or chloroform.[1] Natural bitumin, of lower molecular weight than kerogen, is soluble in ordinary organic solvents. In Colorado oil shales, the kerogen/natural bitumin ratio is about 9:1. Oil is recovered by heating oil shale to 400° C (750° F) and thermally decomposing (pyrolyzing) organic matter.[2]

Under favorable conditions, crude oil can sometimes occur in pore spaces of rocks along with kerogen and natural bitumin. These rocks can yield oil by distillation (without pyrolsis) and are more correctly termed oil shales. In

this report, as in most other oil shale studies, the definition of oil shale includes rocks containing kerogen as well as those containing crude oil and natural bitumen.

4.2 BASIC PROCESSES

Figure 4-1 shows a generic schematic of oil shale processing. Four steps are included in all oil shale proceses: feed preparation, retorting, product recovery, and waste disposal. Atmospheric emissions of criteria pollutants, hazardous pollutants, trace metals, and other materials can occur during each of these steps. The composition and quantity of effluent streams are strongly influenced by the process used to recover shale oil.

Oil shale feed preparation and retort technology can be divided into two general categories: (1) mining, followed by surface retorting, and (2) underground, or in situ, processing. Retort processes currently under investigation can be grouped into three classes: (1) surface, (2) true in situ (TIS), and (3) modified in situ (MIS). In surface retorting technology, oil is recovered in an aboveground retort from shale mined by conventional underground or open pit procedures. In TIS technology, all retorting occurs underground in the shale deposit. MIS technology is a hybrid of surface and TIS technologies in which 60 to 85 percent of the shale is retorted in a place underground, with the remaining 15 to 40 percent being removed and retorted in a surface facility.

Descriptions of processes based on surface and in situ technologies follow. As mentioned above, processes based on MIS technologies are a combination of surface and TIS technologies. Where appropriate, parameters peculiar to MIS technology are included. It should be emphasized that the following descriptions are based on research and development projects, pilot plants, and semi-works facilities. No commercial- or full-sized facility has been built. It is difficult to further define physical environmental concerns, such as air and water quality, until commercial production of oil shale begins. When current technology is scaled-up to full size, some features may change.

4.2.1 Surface Retorting Operations

Figure 4-2 is a block diagram of oil shale operations for surface retorts. Feed preparation processes include shale mining, crushing to size,

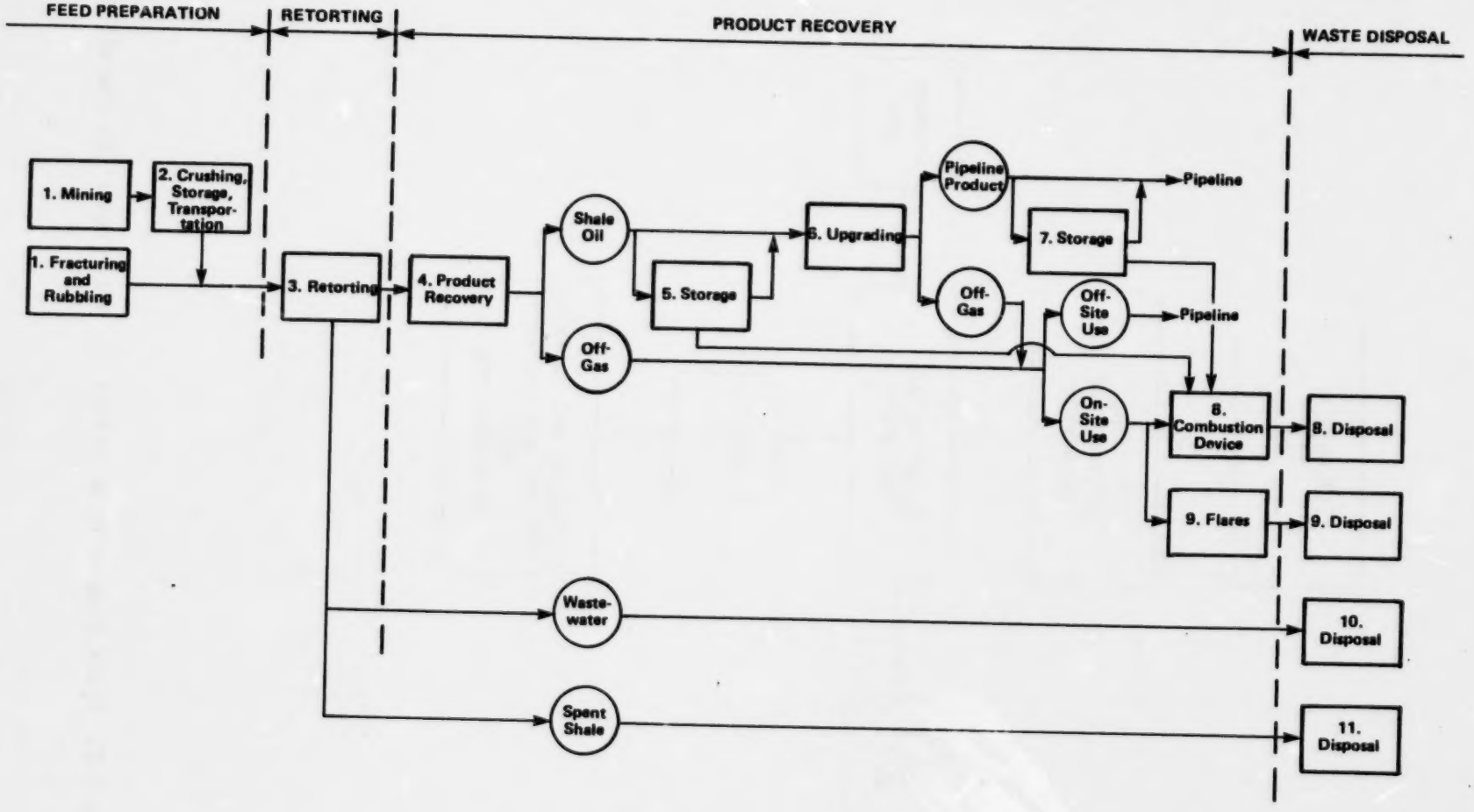

Figure 4-1. Potential sources of atmospheric emissions, oil shale processing.

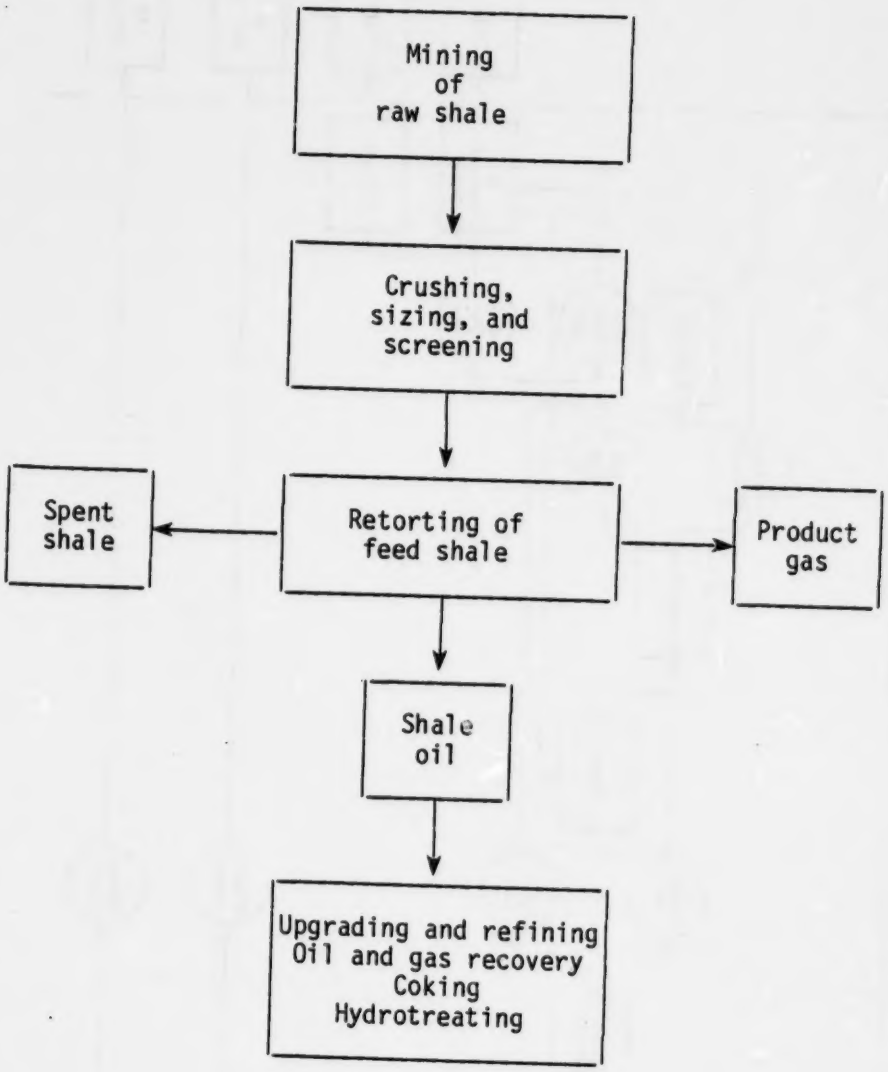

Figure 4-2. Block diagram of a surface oil shale retorting operation.

and transportation. Retorting has three products: shale oil, a product gas, and spent shale for disposal. Shale oil is upgraded to a pipeline product onsite.

4.2.1.1 Mining. Commercial-sized, underground, room-and-pillar mining has been used by several pilot and semi-works retorting facilities. In this process, oil shale is mined from equal-sized openings, approximately 18 meters (60 feet) square, leaving as much as 50 percent of the shale in place as pillars supporting the room. Because so much usable shale is left in the ground, this mining process may not be appropriate for thick shale deposits.

Other underground mining methods can be used effectively to remove oil shale. Sublevel stoping involves blasting to rubble high vertical columns of ore (stopes) and moving oil shale from stopes to rail cars with front-end loaders. Another underground mining method is block caving, in which mine levels are divided into panels and blocks and mined with tunnel methods. Shale from an undercut level is carried by gravity through tunnels and into rail cars.

Surface, or open pit, mining involves excavating overlying soil and rock to expose the resource below. Pit wall slope is determined by stability of the rock being mined, with depth dictated by ore grade. Open pit mining has the advantage of allowing recovery of almost the entire resource.

4.2.1.2 Crushing, Transportation, and Storage. For each of the surface retorting processes, the raw, mined, oil shale must be crushed to appropriate size before transport to a retort. Additional testing of crushing equipment may be required before the best technology is selected, because oil shale fragments are resilient, tough, and slippery and tend to form slab-shaped fragments when crushed in jaw, gyratory, or tooth-roll crushers. Impact-type crushers tend less to cause formation of these slab-shaped fragments.

Current plans for large-scale demonstration plants and commercial facilities generally call for primary crushing at the mine site, followed by secondary crushing near the retorting site. Some retorting processes specify a particle size small enough to require tertiary crushing operations.

According to current plans primary crushed ore will be transported to the retorting site by truck, rail, or in covered conveyors. All commercial plans

currently propose the use of covered conveyors. Dust generated by these operations will be collected and either retorted or discarded.

Primary crushed ore can be stockpiled near the retort to provide for surge conditions and to allow continuous operation through a shutdown of mining activities. Large operations will probably have open stockpiles, with ore being transferred to the retort by traveling buckets or conveyors.

Current plans call for secondary and tertiary crushers to prepare ore for retorting. Storage of fine ores from these operations will probably be enclosed to minimize losses and environmental hazards.

4.2.1.3 Retort Technology. In the surface retort, heat can be transferred in one of three ways: (1) by gases generated within the retort through combustion of carbonaceous, retorted shale and pryrolysis gases (direct heating); (2) by gases heated outside the retort (indirect gas heating); and (3) by hot solid particles mixed with the oil shale (indirect heating with solids). The following subsections describe surface retorting processes with the most potential for commercialization.

4.2.1.3.1 Paraho retorting process. The Paraho surface retorting process operates in the direct- or indirect-heat modes. Most of the experimental work has been done with the direct-heat mode, discussed below (see Figure 4-3).

Raw shale is prepared for Paraho retorting by crushing to a particle size between 1/4 and 3 inches. Raw shale finer than 1/4 inch is screened from the retort feed to avoid a lowering of bed porosity and an increase in bed resistance to the countercurrent gas flow within the retort. After crushing, raw shale is fed into a hopper at the top of the retort and spread evenly on top of the shale bed. After processing, shale is discharged from the retort bottom. Combustion gas containing product gas and oil mist moves countercurrently to the flow of shale and exits near the retort top. An inert gas seal prevents loss of shale oil and product gas through the feed hopper during processing.

Preheated by countercurrent flow of hot combustion gas, shale is pulled downward by gravity through a mist formation and preheating zone. The shale then enters the retorting zone, where contact with hot combustion gases increases shale temperature until kerogen is pyrolyzed to produce oil and gas products. These products are entrained in the combustion gas and carried out

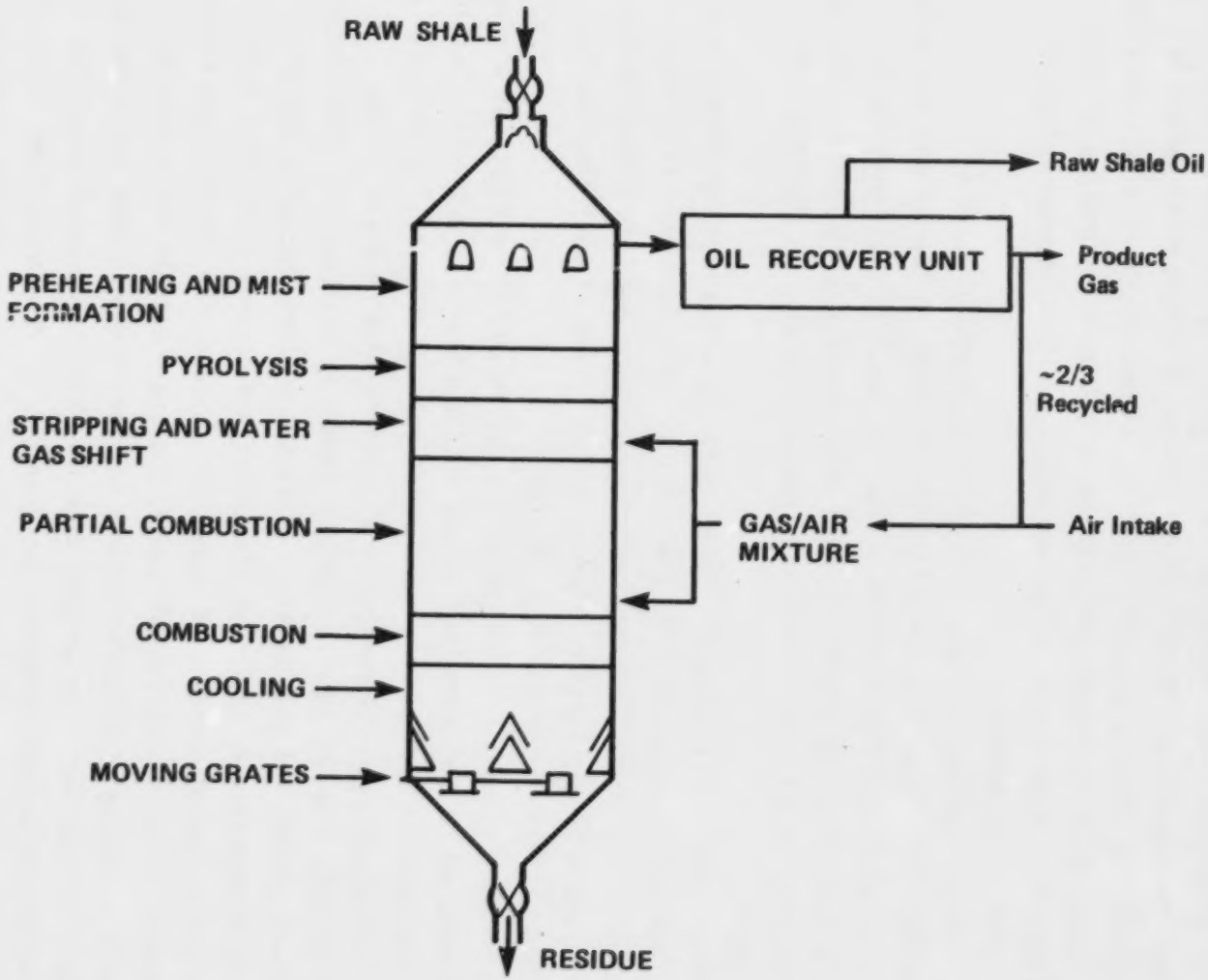

Figure 4-3. Diagram of Paraho process.

of the retort. A coke-carbon residue (4.0 to 4.5 percent by weight) is left on the shale in the retorting zone. As the shale moves into the combustion zone, most of this coke-carbon residue burns, producing hot exhaust gases that supply heat for retorting. At the retort bottom, an adjustable, hydraulic grate controls the shale's downward velocity, maintaining even flow across the retort. Spent shale is discharged from the retort at a temperature of about 200° C (400° F). Spent shale is further cooled as it is transported to the disposal area on conveyors.

Hot off-gas leaving the retort is cooled by incoming shale to approximately 65° C (150° F), converting oil products in the off-gas stream to a mist, that exits the retort in the off-gas stream. This oil product is relatively dust free, has a pour point of approximately 30° C (85° F), and can be recovered by an oil mist separator in conjunction with an electrostatic precipitator.

The oil-free retort off-gas (product gas) has a low heating value (LHV) of 4.5×10^6 J/m^3 (120 Btu/ft^3) on a wet basis. This low value is attributed to dilution of the product gas by combustion products and high concentrations of ammonia and hydrogen sulfide. Retort gas in excess of that required for recycling is available for use as plant fuel.

Approximately two-thirds of retort off-gas is cooled by recycling through gas distributors to the lower half of the retort and mixing with air. Cooling of gas distributors represents a substantial portion of overall plant cooling load. Cooling air supports combustion of coke residue on shale in the combustion zone, and the recycled off-gas serves as a diluent to allow close temperature control and even heating. This temperature control minimizes carbonate decomposition, shale ash sintering, and clinker formation. Little recycle gas is burned during coke combustion, because the incoming gas stream is preheated by the descending hot shale, cooling the shale for discharge.

Shale processed with Paraho retorts has been shown to have approximately 2 percent residual carbon by weight, with the retorting process resulting in approximately 22 percent carbonate decomposition.[3] Some shale feed is crushed while in the retort, resulting in an increased proportion of fine particle material in the discharged (spent) shale.

4.2.1.3.2 TOSCO II retorting process. The TOSCO II retorting process operates in the indirect-heat mode, using hot ceramic balls to heat shale (see Figure 4-4). Because of indirect heat transfer, shale must be crushed to a particle size less than 1/2-inch diameter to allow complete pyrolysis of kerogen. This finely crushed raw shale is preheated to about 260° C (550° F) with hot flue gas from the ball heater and fed into a rotating pyrolysis drum. Ceramic balls are heated to 700° C (1,300° F) in the ball heater and fed into the drum, which mixes the balls and shale. The hot balls heat the shale to about 480° C (900° F), and kerogen pyrolysis occurs. Shale oil vapor is taken from the retort accumulator to an overhead fractionator. After leaving the drum, ceramic balls are separated from spent shale by a rotating trommel. Ceramic balls are reheated and reused. Carbon residue deposited on ceramic balls in the pyrolysis process is used to provide part of the energy required to operate the ball heater; the remainder is provided by process off-gas. Spent shale goes to a heat exchange unit to produce steam for plant use and is then cooled to about 150° C (300° F), moisturized to between 10 to 15 percent water by weight, and disposed of. The shale preheating system is the primary emission source, emitting combustion products, sulfur dioxide, nitrogen oxides, particulates, hydrocarbons, and carbon monoxide.

4.2.1.3.3 Lurgi-Ruhrgas retorting process. The Lurgi retorting process operates in the indirect-heat mode. In this process, raw shale is reduced to the size of less than 8 inches in the primary crushers, with secondary and tertiary crushing further reducing shale particles to less than 1/4 inch in diameter. Crushed, raw shale is fed through a feed hopper into a double screw mixer (see Figure 4-5), where it is thoroughly mixed with four to eight times as much hot spent shale taken from the collecting bin. The spent shale, which has a temperature of 650° to 700° C (1,200° to 1,300° F) heats the raw shale to approximately 510° to 540° C (950° to 1,000° F) within a few seconds. Retorting and distillation occur at these temperatures, yielding product gas, shale oil vapor, and water vapor. The circulating spent shale, which carried the heat, and the partially retorted shale are then dropped from the screw mixer into the surge vessel, where residual oil components are removed by distillation.

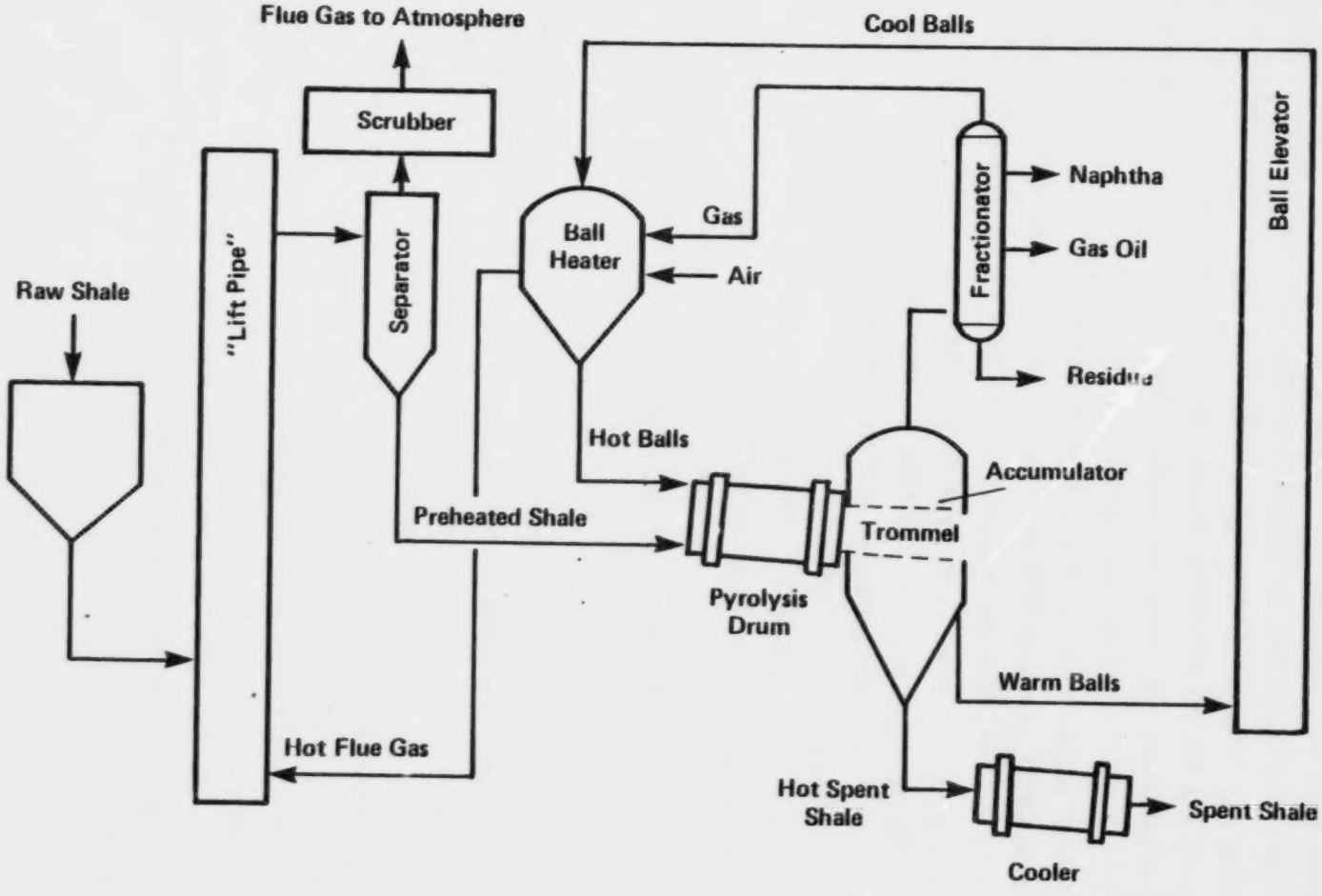

Figure 4-4. Diagram of Tosco II process.

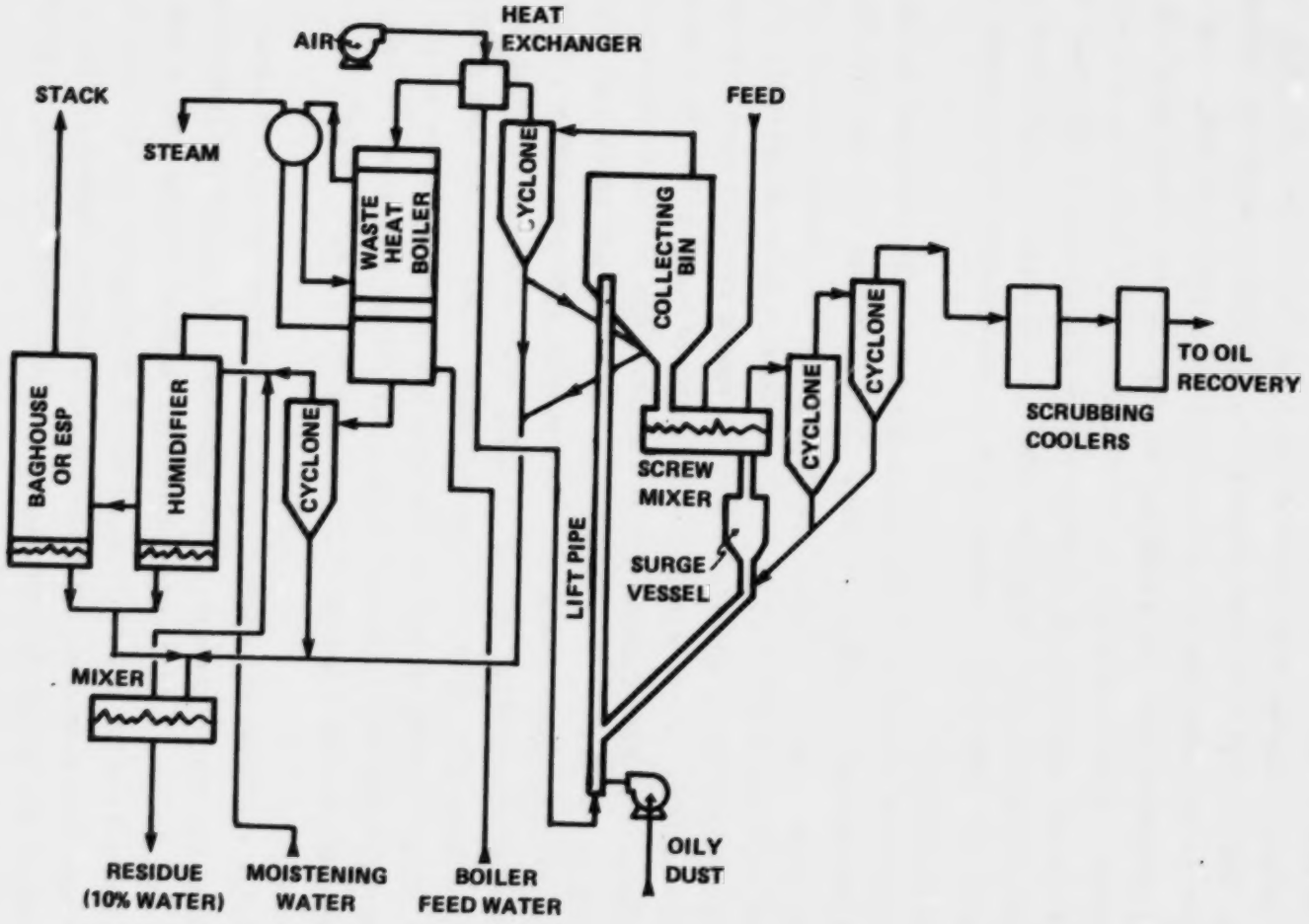

Figure 4-5. Lurgi-Ruhrgas oil shale retorting process.

The mixture of spent shale and retorted shale residue is raised to the collecting bin by a pneumatic lift pipe, into which combustion air, preheated to 230° to 480° C (450° to 900° F), is introduced. Essentially all available organic carbon is burned from retorted shale residue in the lift pipe. In addition, due to high lift pipe temperature, a moderate amount of carbonate decomposes in the spent shale. At the top of the lift pipe, hot, retorted shale is separated from flue gases and returned to the collecting bin as the heat carrier. Fine spent shale is carried out of the collecting bin with the flue gas stream; coarse-grained shale residue accumulates in the lower section of the collecting bin and flows continuously to the mixer. Combustion air supplied to the lift pipe is preheated by countercurrent heat exchange with the flue gas stream.

The product stream is withdrawn at the end of the mixer and passed through two series-connected cyclones. Dust separated in these cyclones is returned to the recycle system. The gas stream then passes through a sequence of three scrubbing coolers. The first scrubbing cooler is designed to operate at a higher temperature than the others to remove residual dust from the gas stream by washing it with circulating, condensed heavy oil. (This scrubber is primarily part of the product recovery process; any pollution control is secondary in its design.) The dust-laden heavy oil may be thinned with light oil to facilitate dust separation. In the next scrubbing cooler, major oil condensation occurs at a temperature above water dew point to produce dust-free heavy oil, which is recovered water free. In the last scrubbing cooler, final cooling of the gas produces gas condensate water or gas liquor, from which middle oil is separated in an oil/water separator. Finally, the gas is scrubbed with light oil for recovery of C_3^+, C_4^+, or C_5^+, as deemed desirable.

After it leaves the collecting bin, lift pipe flue gas is passed through a cyclone and routed through a heat exchanger for preheating combustion air, a waste heat boiler, a feed water preheater, another cyclone, and a humidifier. After humidification and cooling, residual dust may be removed from the flue gas stream by a baghouse. Other particulate control techniques could be used in place of the humidifier and baghouse. Spent shale residue is moisturized

to approximately 10 percent water by weight, cooled to a temperature of about 95° C (200° F), and disposed of.

4.2.2 In Situ Retorting Operations

In situ retorting is the generic name given to recovery processes in which underground shale deposits are heated in place after rock permiability is increased by fracturing or rubbling and, in some cases, after partial mining. Two in situ retorting processes are being developed: the "true" in situ process (TIS), which includes only well drilling and rock fracturing, and the "modified" in situ process, (MIS) which requires mining to develop underground retort chambers. The extent of mining in MIS depends on the retort design. Figure 4-6 is a block diagram for oil shale operations in which in situ retorts are used.

4.2.2.1 True In Situ. In TIS processes, dewatering may be necessary if the shale deposit is below the ground water table. Fracturing or rubbling the deposit may be needed to establish adequate permeability. To remove oil and gas, energy must added, usually in the form of heat, to create a moving fire front, pyrolyzing kerogen as it moves through the bed. Other removal methods under investigation include steam injection and radio frequency heating.

Geokinetics is developing a horizontal TIS retorting process in which blast holes are drilled from the surface, through the overburden, and into the shale bed (see Figure 4-7). These holes are loaded with explosives and fired in specific sequence to yield highly permeable, well-rubbled shale and a sloped bed bottom, from which shale oil and coproducts drain to a sump for recovery by production wells.

After rubbling, oil shale is ignited with burning charcoal at air inlet wells drilled at one end of the retort, establishing a horizontally moving fire front. Off-gases containing oil mist exit through output holes in the retort's downstream end. In Geokinetics' process, these off-gases are passed through an aboveground, three-chamber, packed-tower mist eliminator to remove entrained oil and water. In a commercial facility, these off-gases may be recycled into air inlet wells.

The shale oil and water mixture collected in the sump at the retorts bottom is pumped to an aboveground oil/water separator, along with liquid recovered from the mist eliminator. From the separator, the aqueous layer is

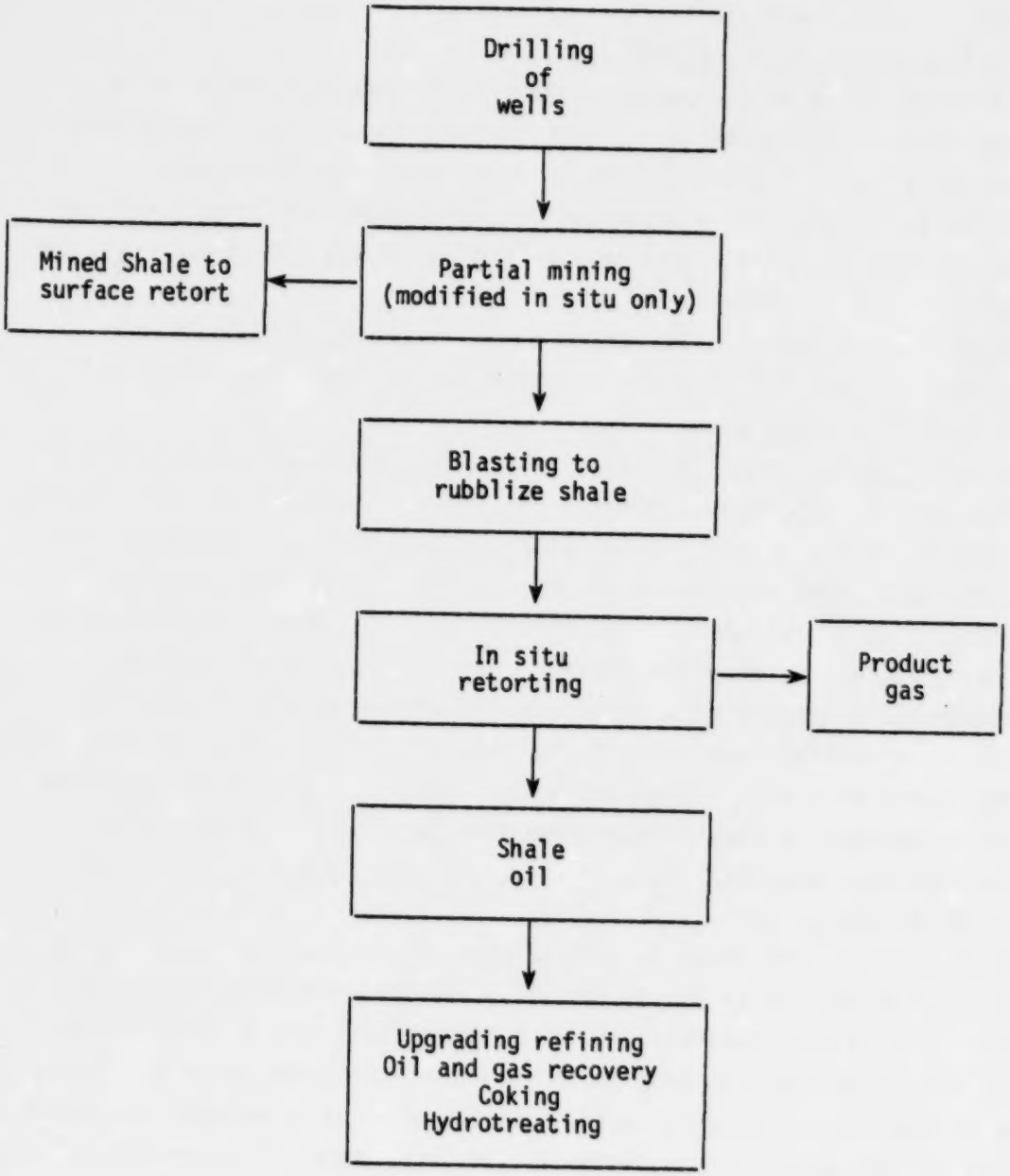

Figure 4-6. Block diagram of an in situ oil shale retorting operation.

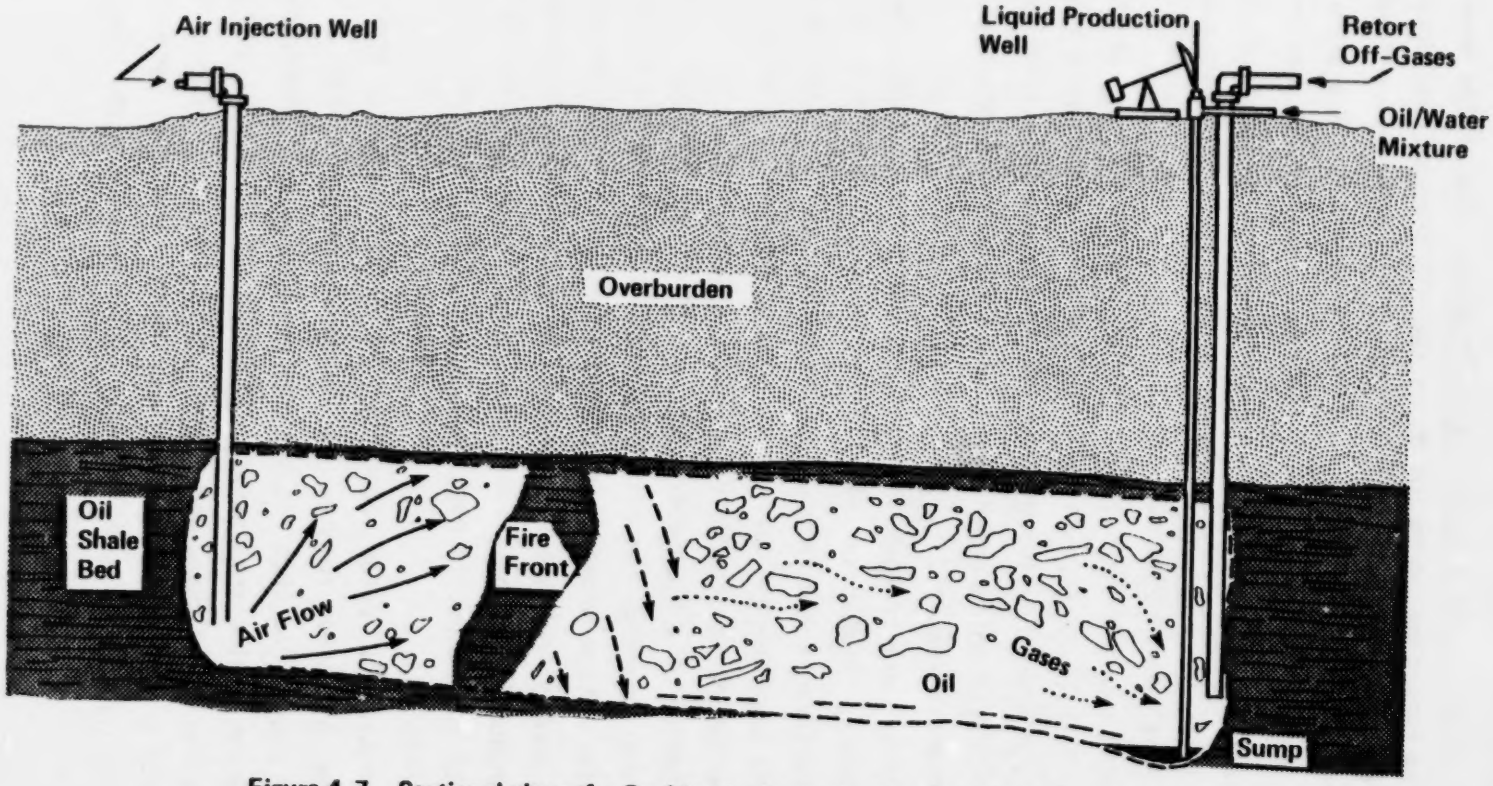

Figure 4-7. Sectional view of a Geokinetics horizontal in situ oil shale retort.

sent to the evaporation pond. Crude shale oil is pumped to storage tanks before upgrading to a pipeline product.

4.2.2.2 Modified In Situ Retorting Process. One of the more thoroughly tested in situ retorting technologies is the MIS process developed by Occidental Petroleum Corporation. Occidental MIS retorts are formed by rubbling vertical sections of oil shale, in place, after approximately 23 percent of a deposit has been mined, creating a void space (see Figure 4-8). In designs by other developers, 15 to 40 percent of the shale might be mined before rubbling. The void space allows for a more complete recovery of kerogen decomposition products.

Occidental type MIS retorts are designed to have three horizontal layers: (1) an upper level, where rubbling holes are drilled and where required process air and steam are introduced; (2) an intermediate level, where additional rubbling holes are drilled; and (3) a production level, where retorting products--shale oil, gas, and water--are collected.

After levels are created through room and pillar mining, shale is fractured through "symmetric" blasting, producing a uniform distribution of space and fractured shale laterally across the retort. Relatively small particle size (averaging 6 inches) and homogeneous distribution of fractured shale in the retort is desirable for efficient operation.

In operation of a MIS retort, air and steam are admitted at the top through several openings connecting the retort air level to the top of the rubbled shale. Steam promotes water/gas reaction and provides means of controlling combustion zone temperature. Retort startup is accomplished through introduction of hot, inert gas. When the temperature of broken rock at the top of the retort is high enough, air and a flame are introduced to initiate combustion.

An operating MIS retort contains four major zones. In the first, a preheat zone, air/steam feed gas is preheated through contact with hot spent shale. The heated gas then reaches the combustion zone, where oxygen is consumed by residual carbon burning in the spent shale. Below the combustion zone is the retorting zone, where hot combustion gases heat raw shale rubble to about 480° C (900° F) for retorting. Here, kerogen is pyrolyzed to produce gas, oil and oil vapor, solid residue, and residual carbon. Shale oil and

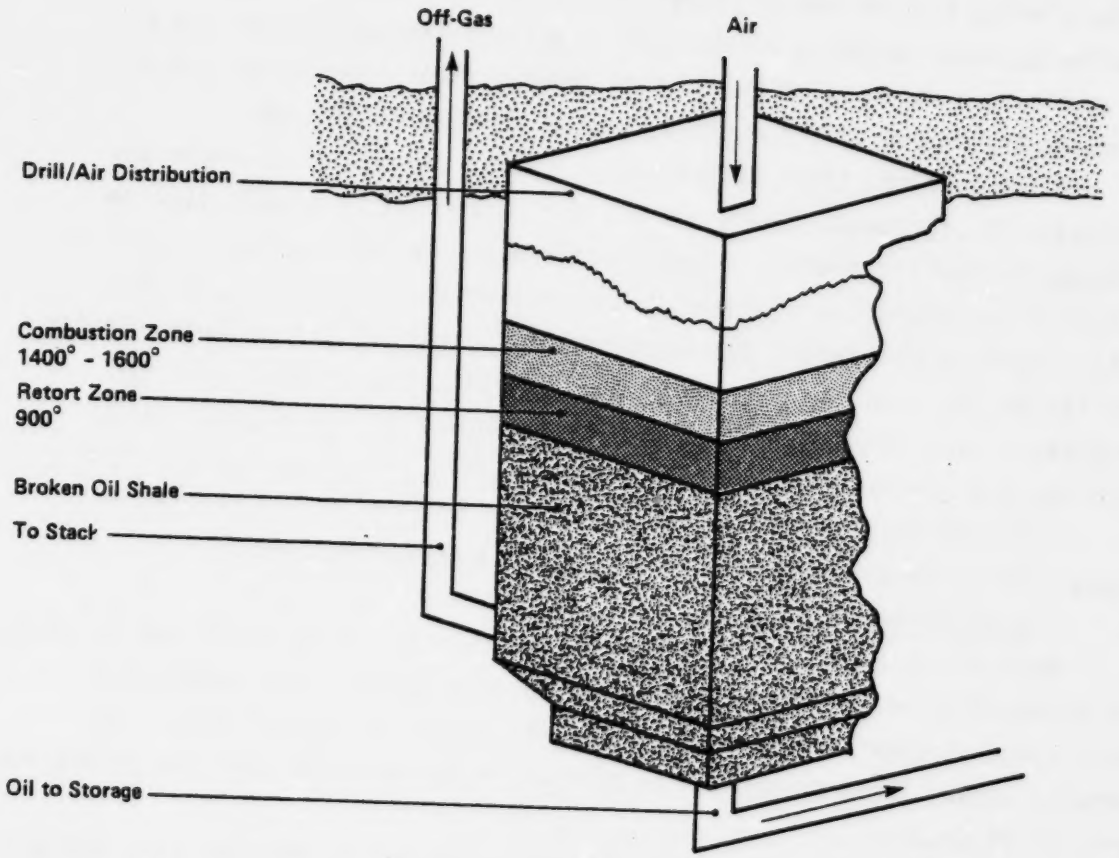

Figure 4-8. Occidental modified in situ process.

coproducts move downward by gravity and preceed the advancing combustion front by 6 to 10 feet. In the final zone, combustion and retorting gases are cooled as they flow downward, condensing some of the vaporized oil and--during early burn stages, when the rock is still cool--some water.

Liquid oil and water condensed in the final zone flow from the bottom of operating retorts into production-level drifts. These drifts are sloped to allow gravity flow of the oil/water stream to the primary oil/water sumps, located adjacent to the production-level drift bulkheads at each end of a cluster of six retorts. After initial gravity separation, water and oil products are pumped to the surface through independent systems.

At the surface, final separation is carried out in oil-in-water and water-in-oil processes. Raw shale oil is transferred to product storage without further treatment. Retort process water can be treated and used as feedwater to produce part of the steam required at the beginning of the retorting process. Retort gases are brought to the surface by large blowers and fed to gas treating equipment, where cooling occurs. This cooling produces a water condensate while the retort gases absorb ammonia, carbon dioxide, and perhaps some hydrogen sulfide. This low-Btu gas with an LHV of 2.6×10^6 J/m^3 (70 Btu/ft^3) may be burned directly or further treated for removal of potential air pollutants, such as H_2S, before combustion.

4.2.3 Spent Shale Disposal

Once oil shale is mined, crushed, and retorted, spent shale must be used or disposed of in an environmentally acceptable manner. The composition and size range of spent shale particles largely depend on type of retorting process used. These properties in turn determine possible uses and method and ease of disposal.

Although spent shale usually occupies a greater volume than raw, inplace shale, it is desirable to place as much of the spent material as possible back in the mine. With proper moisture content, all or part of the spent shale can likely be returned to the mine, packed completely to the roof, and allowed to set. In this manner, mine subsidence can be prevented and unsightly waste piles eliminated. Unfortunately, mining logistics and material handling costs may make this option uneconomical.

Disposal of spent shale in an open pit mine is attractive. Once the open pit is large enough to accommodate both continued operation and spent shale backfilling, all spent shale can be returned to the pit. The pit can then be advanced with ongoing backfilling and reclamation.

Aboveground disposal of spent shale from underground mining/surface retorting operations--proposed by several developers--is a potential alternative to returning spent shale to an underground mine. This technique involves simply disposing of spent shale in the vicinity of the processing facility, where is is compacted and contoured into canyons or valleys or onto relatively flat terrain. A valley site allows for disposal of large volumes, surfaces requiring stabilization and revegetation are relatively small, and most of the spent material is hidden from view. If the disposal site is in a natural drainage path, efforts must be made to reroute natural water flows and to minimize or eliminate natural leaching of water soluble material. Reclamation and revegetation, with appropriate planning, can be conducted along with placement of spent shale. These activities will result in relatively small areas of unreclaimed spent shale at any time during active disposal.

During MIS operations, oil shale mined and removed to the surface may be processed in aboveground retorts, thus creating spent shale requiring disposal. Because this is a relatively low-volume process, it has been proposed that some or all of the spent shale from the surface retorts be slurried and injected into underground retorts in which retorting has been completed.

4.3 INDUSTRY PRODUCTION

4.3.1 Participating Organizations

Investors in research and development efforts and pilot and semi-works facilities include many major U.S. energy companies and several smaller organizations. Table 4-1 contains an up-to-date compilation of companies, development project locations, technologies under development, and contacts. In addition, the following parties also currently have an interest in oil shale development and have provided additional information on resources and technology:

- Laramie Energy Techology Center

TABLE 4-1. COMMERICAL/RESEARCH AND DEVELOPMENT PROJECTS

Name (Owner)	Location	Technology[a]	Contact
Rio Blanco (Gulf and Standard)	Tract C-a, Piceance Creek Basin, Colorado	Vertical MIS and indirect heat-surface	John Selters (303) 878-4052
Cathedral Bluffs (Occidental and Tenneco)	Tract C-b, Piceance Creek Basin, Colorado	Vertical MIS	Chuck Bray (303) 242-8463
White River (Phillips, Sohio, and Sunedco)	Tract Ua/Ub, Bonanza, Utah	Direct and in-direct heat surface retort	Jim Goodlove (801) 363-7628
TOSCO Sand Wash (The Oil Shale Corporation)	Vernal, Utah	Indirect heat surface	Joe Morino (303) 831-4567
(Equity Oil Company)	Piceance Creek Basin, Colorado	In situ-steam injection	-----
Colony (Exxon and TOSCO)	Southern Piceance Creek Basin, Colorado	Indirect heat surface	Robert Lee (713) 656-4626
Union Long Rdige (Union Oil Company)	Southern Piceance Creek Basin, Colorado	Indirect heat surface	John Hopkins (213) 486-6437
(Superior Oil Company)	Northern Piceance Creek Basin, Colorado	Direct heat surface w/mineral recovery	-----
Paraho Develop-ment Corporation	Rifle, Colorado	Direct heat surface (vertical)	Stuart Dykstra (303) 625-2100
IGT (Institute of Gas Tech-nology)	Appalachian Basin	HYTORT	Bob Wilson
(Occidental Oil Shale, Inc.)	Logan Wash, Colorado	Vertical MIS and indirect heat surface	Chuck Bray (303) 242-8463
(Geokinetics, Inc.)	Unitah County, Utah	Horizontal TIS	Rusty Lundberg (801) 353-4343
U.S. Bureau of Mines (Multi-Mineral Corp.)	Northern Piceance Creek Basin, Colorado	In situ w/ mineral recovery	Charlie Sullivan (303) 761-5853

[a] MIS = Modified in situ.
[b] TIS = True in situ.

- Exxon Coal USA
- Chevron
- TRW--Navy Oil Shale Reserves
- Shale Oil Science and Systems, Inc.
- Industrial Resources, Inc.
- Science Applications, Inc.
- The Shaleglon Corporation.

The list in Table 4-1 is reasonably complete. However, interest in oil shale is growing, and the number of interested parties is steadily increasing.

4.3.2 Production Volumes

Historically, shale oil production has been largely undocumented. Table 4-2 lists the few operations in the United States that have produced shale oil. Where a quantity could be determined it is presented. It should be evident that the total quantity of shale oil produced is quite small when compared to the total U.S. or world production of oil.[3]

4.3.3 Growth Trends and Plant Projections for Commercial Production Facilities

4.3.3.1 Status of Oil Shale Projects. Region VIII of the U.S. Environmental Protection Agency (EPA) in Denver, Colorado, has prepared a time table for commercial operations of existing oil shale projects. From this time table, presented in Table 4-3,[4] it is estimated that by 1985 there will be 8 operating commercial oil shale production facilities, with 3 more under construction. By 1990 it is estimated there will be 12 operating commercial facilities, with 2 more under construction. In 1995 it is estimated that there will be a total of 14 commercial oil shale production facilities.

4.3.3.2 Cost and Resource Requirements. Production costs and resource requirements for shale oil cannot be known with certainty until the industry is established. Cost estimates and labor requirements can be made by projecting cost data from current pilot-plant operations or by transferring cost data from similar types of plants. Tables 4-4 and 4-5 present estimates of capital and operating costs,[5] and Table 4-6 presents estimates of labor requirements.[6] Land requirements have been estimated to be from 1,100 to 1,700 acres by 1990, from 5,800 to 8,400 acres by 1995, and from 15,500 to 24,600 acres by the year 2000.[5] Disposal of spent shale may require the most

TABLE 4-2. SHALE OIL PRODUCTION[3]

Dates	Producer/location	Retort type	Oil Production (bbls)
May 1947 to June 1951	Bureau of Mines/ Anvil Points, Colo.	Direct surface-batch	20,300
Jan 1950 to July 1955	Bureau of Mines/ Anvil Points, Colo.	Indirect surface	11,000
1957 to 1958	Union Oil Colo./ Parachute Creek, Colo.	Direct surface	20,000
July 1959 to Dec 1966	The Oil Shale Corp and Denver Research Inst./ Zuni Street, Denver, Colo.	Indirect surface	7,500
1962	Mobil/Rio Blanco Cty., Colo., Beaver Bluff in situ project	MIS (2 burns)	23
May 1964 to Sep 1967	Six company group (Mobil, Humble, PanAm, Sinclair, Continental & Phillips.)/ Anvil Points, Colo.	Indirect surface	25,000
1966 to 1967 1971 to 1972	Colony Development Company/Parachute Creek, Colo.	Indirect surface	180,000
1966 to 1968	Equity Oil Co./Rio Blanco County, Colo.	Experimental MIS	Unknown

(Continued)

TABLE 4-2. SHALE OIL PRODUCTION[3] (Continued)

Dates	Producer/location	Retort type	Oil Production (bbls)
1968 to 1971	Equity and ARCO/ Rio Blanco Country, Colo.	Experimental MIS	Unknown
Apr 1969 to May 1970	Laramie Energy Research Center (BuMines)/ Laramie, Wyo.	TIS test sites 4 & 7	570
Oct 1969 to present	Laramie Energy Research Center (BuMines)/ Laramie, Wo.	Direct surface-batch	1,000 +
1970 to 1972	Shell Oil Co./Piceance Creek Basin	Leaching & TIS retorting	420
1974 to Aug 1976	Seventeen company group/ Anvil Points, Colo.	Direct surface	10,000 +
Dec 1975 to present	Occidental Oil Shale, Inc./ Logan Wash, Colo.	MIS	99,500 and continuing
July 1975 to present	Geokinetics, Inc./ Kamp Kerogen, Utah	TIS	12,000+
1976 to 1979	IGT/Chicago, Ill.	Direct surface	24.5
1976; 1978	Sunoco-Toll Processed/ Brea, Calif.	Direct surface	25
	Anvil Points, Colo.	Direct surface	24

(Continued)

TABLE 4-2. SHALE OIL PRODUCTION[3] (Continued)

Dates	Producer/location	Retort type	Oil Production (bbls)
1977 to Sep 1978	U.S. Navy and Development Engineering Corp./ Anvil Points, Colo.	Direct surface	100,000
June 1979 to present	Equity Oil Co./ Peceance Creek, Colo.	MIS	None at this time

TABLE 4-3. PREDICTED SHALE OIL PRODUCTION LEVELS FROM WESTERN OIL SHALE RESOURCES, 1980 TO 1996[4]
(barrels per calendar day)

Oil shale projects	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996
Occidental oil shale, lease tract C-b	Pilot operation, engr. Permitting, construction				6,250	30,000	50,000	50,000	87,500	140,000	200,000	Commercial operation					
Project Rio Blanco lease tract C-a	Pilot operation, engr. Permitting, construction				19,000	45,600	76,000	Commerical operation, Engr. permitting, construction					90,800	111,600	135,000	Commercial operation	
Geokenetics, Inc., Uinta Basin	Same as above		5,000	5,000	10,000	15,000	25,000	40,000	50,000								
Equity Oil, Piceance Basin	Pilot operation	Plans depend upon outcome of pilot operations															
Naval Oil Shale Reserve, Piceance Basin	Feasibility study				Design, Permitting	Construction					28,000	41,500	50,000	Commercial operation			
Demonstration of above-ground retorting (DOE-PON)	Module modular plant design, construction			8,000	4,000	End project											
Demonstration of advanced retort technology (DOE-PON)	Research				Pilot tests, engineering, permitting Module construction						8,000	8,000	End project				
Union Oil, Long Ridge, Piceance Basin	Construction	9,500	Module oper., construction		30,000	50,000	Commercial operation Scale up							75,000	100,000		
Colony/TOSCO, Parachute Creek, Piceance Basin	Design construction			25,900	38,400	46,200	Commercial operation										
TOSCO Sand Wash, Uinta Basin					Permitting, construction			23,100	46,200								
White River Project, lease tract Ua, Ub, Uinta Basin	Exact schedule will depend upon outcome of litigation													45,000	90,000		
Chevron Oil, Piceance Basin	Engr. permitting, pilot module construction			7,000	15,600	24,200	32,800	41,400	50,000	66,600	83,200	100,000					
Superior Oil, Piceance Basin	Permitting construction				6,700	10,000	12,000	Commercial operation									
Mobil Oil, Piceance Basin	Engineering, permitting construction				6,000	6,000	30,600	42,500	50,000	Commercial operation scale up				78,000	91,500	100,000	
Carter Oil	Engineering, permitting construction				16,600	24,900	30,000	45,000	60,000	Commercial operation							
Cities Services	No definite plans at this time																
Total Projects	0	0	14,500	22,500	81,650	181,300	304,200	337,900	446,800	557,900	693,000	723,100	755,200	821,000	942,400	980,900	989,400

TABLE 4-4. CAPITAL REQUIREMENTS, 1980 to 2000[5]
(billions of 1980 dollars)

	1980 to 1985	1986 to 1990	1991 to 1995	1996 to 2000
Raw shale production	1.25 to 1.38	1.88 to 7.88	8.38 to 10.5	7.38 to 26.4
Upgrading	0.13 to 0.16	0.20 to 0.68	0.87 to 0.91	0.77 to 2.29
Total	1.38 to 2.04	2.08 to 8.56	9.25 to 11.41	8.15 to 28.69

TABLE 4-5. ESTIMATED COSTS AS OF AUGUST 1979 (BASED ON LURGI TECHNOLOGY) FOR PRODUCTION OF 214,000 bbl/DAY OF OIL SHALE ON GOVERNMENT LAND[6]

	Capital cost[a]			Operating cost[b]		Total
Step	%	Cost/bbl, daily capacity	Cost/bbl	%	Cost/bbl	Cost/bbl
Processing	64	$ 6,579	$3.21	30	$1.77	$ 4.98
Mining	27	$ 2,776	$1.35	54	$3.19	$ 4.54
Other	9	$ 925	$0.45	16	$0.94	$ 1.39
Subtotal		$10,280	$5.01		$5.90	$10.91
Upgrading (Hydrotreating)		$ 2,086	$1.00		$3.28	$ 4.28
Total		$12,366	$6.01		$9.18	$15.19

[a]Capital cost, other--support and infrastructure.
[b]Operation cost, other--general and adminstrative costs.

TABLE 4-6. LABOR REQUIREMENTS, 1980 to 2000[5]
(thousands of person years)

	1980 to 1985	1986 to 1990	1991 to 1995	1996 to 2000
Home office	1.5 to 1.8	2.2 to 7.6	9.7 to 10.2	8.6 to 25.5
Field construction	7.0 to 8.8	10.5 to 36.8	46.9 to 49.0	41.3 to 123.2
Operations and maintenance	0.75 to 0.94	6.6 to 14.5	22.5 to 36.9	46.7 to 82.5
Total	9.3 to 11.5	19.3 to 58.9	79.1 to 96.1	96.6 to 231.2

land. Water requirements for aboveground retorts have been estimated to range from 360 to 720 liters (95 to 190 gallons) per barrel of oil. Similarly, it has been estimated that MIS processes will require 360 liters (95 gallons) of water per barrel of oil and that TIS proceses will require 340 liters (90 gallons) water per barrel of oil.[5]

4.4 REFERENCES

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5. AIR EMISSIONS DEVELOPED IN SOURCE CATEGORY

5.1 INTRODUCTION

This chapter identifies and evaluates emission sources at oil shale facilities to determine need, if any, for regulation under Sections 111 and 112 of the Clean Air Act, as amended. Availability of emission test data from various oil shale facilities, methods used to acquire these data, and data quality were assessed to achieve this goal. Emissions of both criteria and noncriteria pollutants were considered.

Of potential synthetic fuel industries, the oil shale industry is perhaps closest to commercialization in the United States. Several consortia and companies have been developing oil shale technology for some time and have established pilot-plant-scale projects in prime areas of Colorado and Utah. The overall commitment by these organizations indicates good prospects for full commercialization in the 1980s.

Because no commercial facilities presently exist, the data base on oil shale pollution problems and control is meager, derived primarily from bench-scale and pilot-plant operations. Extrapolation, to commercial scale, of available oil shale data may have limitations and will require valididation. However, bench-scale and pilot-plant data can help approximate environmental pollution problems and will indicate potential approaches for development.

Unfortunately, uncontrolled emission data for bench-scale and pilot-plant oil shale operations were not accessible for this study. These data--used by oil shale developers to project controlled emissions from planned facilities for permit applications--have instead been approximated by reconstructing and then reversing the developers' estimation process. Specifically, developers usually estimate controlled emissions from bench-scale, pilot-plant, or process material balance data by applying control factors equal to emission limitations perscribed in applicable State Implementation Plans (SIPs). (See Chapter 1 for a review of State regulations applicable to the oil shale

industry.) Thus, uncontrolled emission data presented in this study have been backed out with applicable SIP control factors from estimated controlled emissions listed in oil shale developers' permit applications.

Because these uncontrolled emission data are approximated rather than actual, they may be insufficient for judgments of individual processes or regulatory actions. They are presented here as uncontrolled emission estimates and therefore can only grossly define emission control problems the industry may encounter as it develops. As development proceeds, it is hoped that these emissions estimates will be refined and upgraded. The scheduled burn of a Occidental modified in situ (MIS) retort No. 7 at Logan Wash during November 1981 through May 1982 could provide actual uncontrolled emissions data.

5.2 AVAILABILITY OF DATA

During this study the following computer data bases were searched for references to environmental impacts of extraction-acid processing of oil shale:

- National Technical Information Service (NTIS)
- Compendix
- APILIT
- Chemical Abstracts
- Enviroline
- Energyline.

In each data base, data were sought under the following listings:

- Shale oil
- Synthetic fuel
- Retorting
- Oil recovery
- Mining
- Crushing
- Screening
- Retorting
- Oil recovery
- Oil refining
- Particulates
- Sulfur compounds
- Oxides of nitrogen
- Carbon monoxide
- Hydrocarbons (VOCs)
- Trace metals
- Polycyclic organic material (POM)
- Arsenic.

Several references were identified as containing emission data relative to oil shale retorting.[1,2,3,4,5,6,7] Studies on retorts described in the following subsections were evaluated for scientific validity and engineering significance.

5.2.1 Geokinetics In Situ Retorting

Potential pollution sources of Geokinetics Retort No. 17 were characterized by Monsanto Research Corporation (MRC).[5] Particulate matter and trace element sampling was performed with a modified U.S. Environmental Protection Agency (EPA) Method 5. Particulate matter emissions in the incinerator exhaust were 4.2 ton/yr (0.43 kg/hr). The sampling system probe had a stainless steel liner that may have been corroded by the sampled gases, biasing the total mass values. Analysis of incinerator outlet samples indicated presence of tin, lead, and arsenic. The impinger media collection efficiency is not completely documented and may not be high enough to prevent negative bias of data on volatile trace elements, which are of environmental concern. There are no data on emitted particulate matter sizing or composition. These parameters are necessary to properly characterize particulates.

5.2.2 Paraho Semi-Works Oil Shale Retort

Battelle Pacific Northwest Laboratory completed mass balances for 31 trace elements from the Paraho semi-works retort operated in the direct-heat mode.[7] The relative distribution of elements among products and effluents was determined with accuracy and high precision in raw shale, retorted shale, product oil, product water, and product gas. Data show 1 percent or greater mass fractions of arsenic, cobalt, mercury, nitrogen, nickel, sulfur, and selenium are released during retorting and distributed to the product shale oil, retort water, or product off-gas. Fractions of these seven elements ranged from 1 percent for cobalt and nickel to 50 percent for mercury and nitrogen. Comparison of elemental distribution in various products indicates that several retorting techniques exhibit common general patterns with respect to redistribution of inorganic species. No sampling for particulate sizing or its characterization was performed in this study.

TRW conducted an environmental testing program at the Paraho Shale Oil demonstration plant.[1] This program emphased measurements of recycle gas from the Paraho retort and combustion products from a thermal oxidizer fueled by

recycle gas and auxillary fuel. Measurement included particulate matter, As, and Hg. The impinger catch was not analyzed for Se and other volatile trace elements, although TRW reports stibine (SbH_3) at concentrations below the detection limit.

5.2.3 Laramie Energy Technology Center In Situ Oil Shale Retorting

MRC evaluated particulate control efficiency of a 150-ton oil shale retort at the Laramie Energy Technology Center.[8] Because of small retort duct size, single-point sampling was used to determine particulate emission rates with an EPA-approved method. Particle size distribution was measured with Anderson Mark III cascade impactors. A preimpactor was used to separate coarse particles. Glass fiber collection substrates were used because the particulate matter was oily. Sampling duration was 10 minutes at the inlet and 20 minutes at the outlet. Outlet sampling time was too short because of the low concentration of particulates in the outlet, and good size distribution data were not be obtained. Therefore, only inlet data are reported. Inlet data show that more than half the partculates (by weight) have a diameter less than 5 μm, with about 10 percent having a diameter less than 1 μm. Size distribution appeared bimodal, with fractions larger than 20 μm (approximately 35 percent) and between 1 and 2 μm predominating.

Method 5 sampling indicated the retorting off-gases contained particulate matter that can condense between 120°C (250° F) and about 20°C (70° F). The inlet particulate concentration was found to be highly variable, ranging from 125 to 387 mg/m^3. A venturi scrubber consistently achieved an average outlet concentration of 35 mg/m^3 despite the three-fold variation in inlet concentrations. Data show an average scrubber collection efficiency of 86 percent. No attempts are reported to characterize the particulate matter in terms of chemical composition.

5.3 PROCESS EMISSIONS REVIEW

Although oil shale deposits occur throughout the world, U.S. deposits are among the richest, most extensive, and best explored. Oil shale is commonly defined as a fine-grained, sedimentary rock containing kerogen, an organic matter that yields oil during pyrolysis. Two methods for producing oil from oil shale are under active investigation: surface retorting and in situ

retorting. In both methods, sources of air pollutant emissions include mining, processing, retorting, and processed shale disposal processes.

5.3.1 Mining

Mining activities in the oil shale industry are expected to be among the largest in the world. Potential exists for atmospheric pollution in all phases of mining--excavation, blasting, crushing, transfer, and equipment operation. Although open-pit mining has been suggested as a surface mining technique applicable to oil shale extraction, no developer currently has plans to employ it.[4] Consequently, only underground mining operation data are presented. Table 5-1 shows atmospheric emission estimates (control system not reported) for underground mining operations required to support a 50,000-bbl/day shale oil facility. These estimates are based on limited information and only provide ranges within which atmospheric emissions from mining might fall.

5.3.2 Processing

Fugitive dust from processing raw shale for retorting is a significant source of particulate matter emissions. All surface retorting operations require size reduction of mined shale, and some surface retorts require secondary crushing. Transportation and disposal of processed shale also contribute to particulate loading in ambient air. Table 5-2 shows estimate controlled emissions for primary and secondary crushing and for transportation and storage. While degree of control is not specified in Table 5-2, it is reasonable to assume that control systems for stone quarrying and processing are also applicable for raw oil shale processing. Control efficiencies for these systems typically range from 75 to 99 percent for primary and secondary crushing operations.[9]

Controlling fugitive emissions from raw shale storage and transportation normally consists of wetting or covering, from which 80 percent control efficiency is estimated.[10] Assuming 80 percent capture efficiency at the crushers and applying applicable SIP emission factors to controlled emission data results in the following estimates of uncontrolled particulate emissions from primary and secondary crushing, storage, and transportation of mined shale (normalized to a 50,000-bbl/day shale oil operation):

TABLE 5-1. ESTIMATED UNCONTROLLED ATMOSPHERIC EMISSION RANGES FOR UNDERGROUND MINING OPERATIONS--50,000-bbl/DAY SHALE OIL FACILITY[11]

Mining operation	Atmospheric emissions (Mg/day)[a,b]				
	Particulate matter	Sulfur dioxide	Nitrogen oxide	Hydrocarbons	Carbon monoxide
Excavation (mining)	0.01 to 0.92	0.08[c]	2.95[c]	Not reported[d]	Not reported[d]
Blasting	0.03 to 19.15	Not reported	0.36 to 0.77	Not reported	0.359 to 0.768
Ground vehicles	0.01 to 0.15	0.004 to 0.005	0.007 to 2.99	0.01 to 0.59	0.03 to 5.18
Total	0.08[e] to 20.22	0.004[f] to 0.089	0.007[e] to 3.769	0.01[e] to 0.59[f]	0.039[e] to 5.18[d]

[a]Columns may not total because ranges are from different programs.
[b]Degree of control unknown; assumed to be uncontrolled.
[c]Only value reported.
[d]Emissions from excavation were not reported.
[e]Emissions from blasting were not reported.
[f]Consists of only ground vehicle emissions.
[g]Consists of only excavation emissions.

TABLE 5-2. ESTIMATED CONTROLLED PARTICULATE EMISSIONS FROM CRUSHING, TRANSPORTATION, AND STORAGE OF RAW SHALE AND DISPOSAL OF SPENT SHALE--50,000-bbl/DAY OIL SHALE FACILITY[12]

Operation	Atmospheric emissions, Mg/day (ton/day)[a,b]	
Primary and secondary crushing	0.292 to 1.030	(0.322 to 1.135)
Storage and transportation[c]	0.043 to 0.192	(0.047 to 0.212)
Total	0.335 to 1.175	(0.369 to 1.295)

[a]Columns may not total because ranges are from different programs.
[b]Degree of contol not reported.
[c]Includes spent shale disposal.

- Primary and secondary crushing, 0.468 to 0.515 Mg/day (0.516 to 0.568 ton/day)
- Storage and transportation, 0.072 to 0.181 Mg/day (0.079 to 0.200 ton/day).

5.3.3 Retorting

Processing and disposal of shale oil and off-gases produced during retorting is a major air pollution problem for the oil shale industry. For the purposes of this study, retorting emissions include those from retorting, from subsequent treatment of shale oil and offgases, and from onsite use and dispoal of off-gases.

Covering all retorting technologies, the following are ranges of estimated controlled emissions from oil shale retorting in a 50,000-bbl/day facility:[13]

Pollutant	Range of estimated controlled emissions	
	Mg/day	ton/day
Particulate matter	0.13 to 7.81	0.14 to 8.60
Sulfur oxide	0.20 to 19.00	0.22 to 20.94
Nitrogen oxide	6.02 to 64.16	6.63 to 70.70
Hydrocarbons	0.27 to 28.25	0.30 to 31.13
Carbon monoxide	0.43 to 1.91	0.47 to 2.11

No degree of control was reported, nor any explanation given for orders of magnitude differences in some ranges.

Except for sulfur oxides, data are insufficient for estimating uncontrolled retorting emissions. During retorting, sulfur can be released to the atmosphere in several ways. Raw shale contains sulfur, both organically (approximmately 33 percent) and inorganically bonded. During pyrolysis and/or partial oxidation, the organic fraction undergoes reaction, with about 40 percent released as hydrogen sulfide and other gaseous sulfur compounds such as sulfur dioxide, carbon disulfide, carbonyl sulfide, and, possibly, thiocyanates--all of environmental concern. The rest of the organic sulfur remains in the shale oil as heavier sulfur-containing compounds. For ease of comparison and because sufficient data characterizing effluent streams are not

available for each sulfur compound, emissions are estimated as sulfur dioxide equivalents. Based on a yield of 60 to 125 ℓ/Mg (15 to 30 gal/ton) of shale,[14] uncontrolled sulfur oxide emissions from retorting are estimated to at 120 and 240 Mg/day for a 50,000-bbl/day facility.

Nitrogen oxides can result from burning or pyrolyzing of fuel containing nitrogen and can be produced from elemental nitrogen in the oxidizing medium. Nitrogen oxides formation rate depends on fuel nitrogen content and combustion conditions. Raw oil shale is nitrogen rich and may be a significant nitrogen oxides source.

Pyrolyzing atmosphere is low in oxygen, so significant amounts of hydrocarbons are present in the gas stream. Similarly, carbon monoxide is formed from incomplete combustion. To date, attempts to characterize hydrocarbons in oil shale retort emissions have been limited.

Retorting operations also emit particulates, with amounts depending on type of retort. Trace elements may be included in particulate matter and may be emitted both as vapors and as solids, possibly as submicron-sized aerosols. Limited research indicates arsenic, mercury, iron, chromium, and zinc as possible trace-element emissions.[1,15,16]

Trace element emissions from oil shale retorting could be problematic and warrant more research, as do sample preservation, sample preparation, and analysis methodology. Experience indicates that analytical parameters such as precision, accuracy, sensitivity, and specificity are highly dependent on sample matrix. Therefore, analytical methods should be evaluated for these parameters to increase the data validity and usefulness. Trace element emissions may also depend on pyrolysis conditions. Work related to size-dependent sampling and chemical characterization of particle size classes needs to be performed, although the literature reports only one investigation of size dependent sampling.[5]

Table 5-3 contains reported composition of shale oil retort off-gases for five technologies.[3] While compositions shown in Table 5-3 are based on limited data, they serve as a screen for selecting sulfur removal technolgies to consider for application to the oil shale industry.

TABLE 5-3. COMPOSITION OF OIL SHALE RETORT OFF-GASES[3]

Retort type[a]	Composition (Average Volume %)											Comments
	C_1^+	CO_2	CO	H_2	H_2S	Other Reduced Sulfur	NH_3	N_2	O_2	SO_2	NO_x	
Paraho direct heated surface	5.22	22.81	2.50	4.74	0.30	b	0.70	63.8	0.9	17 ppm	168 ppm	Mean values observed during 1977 and 1978
Occidental, MIS	3.76	32.26	0.89	7.65	0.10	40 ppm[c]	d	56.41	0.08	0.15	0.03	Gas produced at midpoint of Retort 6 run
Geokinetics, TIS	2.43	23.48	8.03	7.47	0.13	40 ppm[e]	0.06	57.4	1.13	d	d	Average composition, Retort 18
Union Oil, indirect-heat surface	51.19	16.62	4.85	23.34	3.82	726 ppm	d	0.11	d	125 ppm	d	Estimate composition; not based on active burns.
TOSCO II, indirect-heat surface	51.19	20.38	3.40	20.20	4.12	170 ppm	f	g	g	g	g	Average composition produced by TOSCO II retort

[a]MIS = modified in situ; TIS = true in situ.
[b]No CS_2, RSN, COS detected. Organic sulfur compounds 250 ppm.
[c]COS only range 1-40 ppm. No data on other reduced sulfur species.
[d]No data.
[e]COS only. No data on other reduced sulfur species.
[f]Partitioned into water phase. Does not appear in gas.
[g]None reported.

5.3.4 Spent Shale Disposal

Disposing of large quantities of spent shale presents a problem, except in the true in situ (TIS) process. Transfer, handling, and disposal could cause problems of particulate entrainment and/or hydrocarbon vaporization from hot shale. Some trace elements also might be involved in such emissions. Sufficient information regarding emissions from spent shale disposal could not be identified.

5.4 EMISSION FACTORS

As discussed in Chapter 4, seven separate proposals exist to construct commercial oil shale retorting plants with the intent to develop a commercial project. Table 5-4 contains brief descriptions of these projects, estimated emissions, and planned control systems. These emission rates are gross estimates based on pilot-plant and bench-scale emissions data and material balances.

Data in Table 5-4 can be used to estimate uncontrolled emissions from shale oil processing. These estimates are shown in Tables 5-5 and 5-6 normalized to 1,000 barrels of shale oil. The range of estimated emission factors can be summarized as follows:

Pollutant	Uncontrolled emission factor, kg/10^3 bbl (lb/10^3 bbl) shale oil	
Particulate matter	61 to 242	(134 to 534)
Sulfur oxide	550 to 6,600	(1,212 to 14,553)
Nitrogen oxide	93	(205)
Hydrocarbons	60 to 3,980	(132 to 8,775)
Carbon monoxide	280 to 1,420	(617 to 3,131)

These data reflect emission ranges reported for the seven proposed commerical facilities and are presented to illustrate ranges that could be experienced. These ranges are based on estimated emissions and could be greater because of high uncertainty for data upon which these ranges are based. Emission factors for a specific facility must be determined based on technology, production rate, and control system used. Because of data

TABLE 5-4. ESTIMATED EMISSIONS, OIL SHALE PROJECTS[18]

Developer	Planned capacity, bbl/day	Retort technology	Controlled emissions[a]										Control systems
			Particulate matter		Sulfur oxide		Nitrogen oxide		Hydrocarbons		Carbon monoxide		
			kg/10^3 bbl shale oil	Mg/day	kg/10^3 bbl shale oil	Mg/day	kg/10^3 bbl shale oil	Mg/day	kg/10^3 bbl shale oil	Mg/day	kg/10^3 bbl shale oil	Mg/day	
Rio Blanco 10-year MDP	b	Modified in situ	--	0.3	--	1.9	--	9.7	--	0.3[c]	Not reported		Incineration and Na_2CO_3 scrubber
Commercial Development	76,000[d]	Modified in situ	68	5.1	66	5.0	339	25.8	24	2.5[e]	Not reported		Sulfinol H_2S removal for surface retort gas. Stretford H_2S removal in situ gas
Cathedral Bluffs	57,000	Modified in situ[f]	14	0.8	33	1.9	112	6.4	3	0.2	16	0.9	Stretford H_2S removal
White River													
Phase II	6,000[g]	Combination of direct- and indirect-heat surface retort	120	0.7	15	0.1	197	1.2	2	<0.1	24	0.1	Not reported
Phase III	100,000		99	9.9	33	3.3	294	29.4	12	1.2	34	3.4	Not reported
Colony Development	47,000	Indirect-heat surface retort	53	2.5	66	3.1	361	16.9	63	3.1	14	0.7	Gas treatment to remove H_2S and CO_2; gas removal by diethanolamine absorption; CLAUS plant with a Wellman-Lord tail gas cleanup
Union Oil[h]	9,000[i]	Indirect-heat surface retort	51	0.5	98	0.9	120	1.1	52	0.5	71	0.6	Venturi scrubber, Stretford H_2S Removal
Superior Oil	11,586	Direct-heat surface retort	71[j]	0.8[j]	326	3.8	162	1.9	19[k]	0.2[k]	44	0.5	Not reported
Occidental	[l]	Modified in situ	--	0.1	--	0.3[m]	--	0.6	--	1.7	--	39.3	Stretford unit on slip-stream of retort off-gas
TOTAL[n]				2.00		20.2		91.8		9.7		45.4	

[a]Includes emissions from all mining and processing activities unless otherwise indicated.
[b]Includes three retorts, largest of which will have 750 bbl/day capacity.
[c]Includes 0.3 Mg/day from tank vapor losses.
[d]Shale from drift and retort development will be processed in a TOSCO II indirect-heat surface retort. Rio Blanco is also studying the Lurgi-Rubirgas.
[e]Includes 0.7 Mg/day from tank vapor losses.
[f]Raw shale produced during mine development (estimated at 41,000 ton/day) will be disposed of without retorting.
[g]Estimated from data in Reference 1, p. A-21.
[h]Test project.
[i]Experimental retort. Commercial modification projected at 100,000 bbl/day.
[j]Includes emissions from nacholite and alumina recovery processes.
[k]Nonmethane hydrocarbons.
[l]No data given; research and development installation.
[m]41 Mg/day H_2S also estimated.
[n]Totals do not include White River Phase I emissions.

TABLE 5-5. ESTIMATED UNCONTROLLED PARTICULATE MATTER, SULFUR OXIDE, AND NITROGEN OXIDE EMISSION FACTORS--OIL SHALE PROCESSING, ALL EMISSIONS SOURCES

Developer	Particulate matter[a]	Sulfur oxide				Nitrogen oxide			
	Uncontrolled emissions, kg/10^3 bbl shale oil	Controlled, emissions, kg/10^3 bbl shale oil	Control system		Uncontrolled emission factors, kg/10^3 bbl of shale oil	Controlled emissions, kg/10^3 bbl of shale oil	Control system		Uncontrolled emission factors, kg/10^3 bbl shale oil
			Type	Efficiency (percent)			Type	Efficiency (percent)	
Rio Blanco	104 to 242	66	Sulfinol Oil	96 to 99[b]	1,650 to 6,600	339	Not reported	INS	INS
Cathedral Bluffs	INS	33	Stretford	94[b]	550	112	Ammonia removal	93[c]	1,600
White River, Phase III	301	33	Not reported	INS	INS	294	Not reported	INS	INS
Colony	61	66	Claus plus Wellman Lord	97.5 to 98.5[d]	2,640 to 4,400	361	Not reported	INS	INS
Union Oil	INS	98	Stretford	94[b]	1,633	120	Not reported	INS	INS
Superior Oil	INS	326	Not reported	INS	INS	162	Not reported	INS	INS

INS = Insufficient data.

[a]Reference 15.
[b]Estimated from data--Reference 16.
[c]Reference 17, p. 25.
[d]Based on a Claus efficiency of 65 to 85 percent and Wellman Lord 90 percent.

TABLE 5-6. ESTIMATED UNCONTROLLED HYDROCARBON AND CARBON MONOXIDE EMISSION FACTORS--OIL SHALE PROCESSING, ALL EMISSION SOURCES

Developer	Hyrdocarbons			Carbon monoxide		
	Controlled emission factors, kg/10^3 bbl shale oil	Control efficiency[a]	Uncontrolled emission factors, kg/10^3 bbl shale oil	Controlled emission factors, kg/10^3 bbl shale oil	Control efficiency[a]	Uncontrolled emission factors, kg/10^3 bbl shale oil
Rio Blanco	24	95	486	Not reported	95	INS
Cathedral Bluffs	3	95	60	16	95	320
White River, Phase III	12	95	240	34	95	680
Colony	63	95	1,260	14	95	280
Union Oil	52	95	1,040	71	95	1,420
Superior Oil	199	95	3,980	44	95	880

INS = Insufficient data.

[a]Assumed to be an after burner.

limitations, extrapolation to commercial scale emission rates may not yield accurate values.

5.5 ESTIMATES OF NATIONWIDE EMISSIONS

The oil shale industry is one of the few synfuel industries currently showing rapid development. Although commercialization is planned within the next few years, only seven firms have filed the Detail Development Plan and other related documents required for commercialization. Based on data from these firms, nationwide emissions from oil shale industries can be estimated. As previously mentioned, emissions data upon which these estimates are made are from limited pilot-plant and bench-scale operations. While individual data have high uncertainty, resulting estimates indicate the nature and extent of air pollution problems associated with oil shale processing. For the estimates, air emissions from various process streams of some proposed oil shale plants were not included because they lacked information on current status. When such data are available, these estimates should be revised.

Based on the program development schedule shown in Table 4-3 (see Chapter 4) and on estimated emissions shown in Tables 5-5 and 5-6, estimated nationwide actual emissions of criteria pollutants for 1985, 1990, and 1995 are shown in Table 5-7. Similar estimates for noncriteria pollutants, including trace metals, cannot be made until more emission data are available. Emissions shown in Table 5-7 are based on estimated production data provided by industry and represent emissions after the control systems currently planned for installation.

Estimated uncontrolled emissions for 1985, 1990, and 1995 are shown in Tables 5-8 through 5-12 for particulate matter, sulfur oxide, nitrogen oxide, hydrocarbons, and carbon monoxide, respectively. These data are rough estimates and should be refined as more emission data become available. Nitrogen oxide emission estimates are especially questionable in that the industrywide estimate is based on data from only one planned facility.

It should be noted that emission estimates are based on projected production levels made in the late 1970s. There has been slippage in target dates. However, estimated emissions provide a time series of how emissions

TABLE 5-7. ESTIMATED ACTUAL EMISSIONS OF CRITERIA POLLUTANTS FROM PLANNED OIL SHALE DEVELOPMENT PROJECTS--1985, 1990, AND 1995

Developer	1985						1990						1995					
	Projected production, bbl shale oil per calendar day[a]	Emissions, Mg					Projected production, bbl shale oil per calendar day[a]	Emissions, Mg					Projected production, bbl shale oil per calendar day[a]	Emissions, Mg				
		Particulate matter	Sulfur oxide	Nitrogen oxide	Hydrocarbons	Carbon monoxide		Particulate matter	Sulfur oxide	Nitrogen oxide	Hydrocarbons	Carbon monoxide		Particulate matter	Sulfur oxide	Nitrogen oxide	Hydrocarbons	Carbon monoxide
Projects for which estimated emissions data were available																		
Rio Blanco	45,000	1,117	1,084	5,568	394	b	76,000	1,886	1,831	9,404	666	b	135,000	1,886	1,831	9,404	666	b
Cathedral Bluffs	30,000	153	361	1,226	33	175	200,000	1,022	2,409	8,176	219	1,168	200,000	1,022	2,409	8,176	219	1,168
White River	--	--	--	--	--	--	--	--	--	--	--	--	90,000	3,252	1,084	9,657	394	1,117
Colony	38,400	743	925	5,060	833	196	46,200	894	1,113	6,588	1,062	236	46,200	894	1,113	6,588	1,062	236
Union Oil	30,000	558	1,073	1,314	569	774	50,000	931	1,789	2,190	949	1,296	100,000	1,862	3,577	4,380	1,898	2,592
Superior Oil	6,700	174	797	396	46	108	12,000	311	1,428	710	83	193	12,000	311	1,428	710	83	193
Subtotal	150,100	2,745	4,240	13,564	1,875	1,253	384,200	5,044	8,570	27,068	2,979	2,893	583,200	9,227	11,442	38,915	4,322	5,306
Project for which estimated emissions data were not available																		
Occidental[b]	--						--						--					
Geokinetics[c]	15,000						50,000						50,000					
Naval Oil Reserve[c]	--						28,000						50,000					
IOSCO, U-b[c]	--						46,200						46,200					
Chevron[c]	15,600						66,600						100,000					
Mobil[c]	--						50,000						91,500					
Carter Oil[c]	--						60,000						60,000					
Subtotal[d]	30,600	560	864	2,765	382	255	300,800	3,949	6,710	21,192	2,332	2,265	397,700	6,292	7,803	26,537	2,947	3,618
Total	180,700	3,305	5,104	16,329	2,257	1,508	685,000	8,993	15,280	48,260	5,311	5,158	980,900	15,519	19,247	65,452	7,269	8,924

[a]Reference 19.
[b]No data reported.
[c]No emission data available.
[d]Emissions estimated on assumption that average emission factors are the same as those for which emission data are available.

TABLE 5-8. ESTIMATED UNCONTROLLED PARTICULATE MATTER EMISSIONS FROM PLANNED OIL SHALE DEVELOPMENT PROJECTS--1985, 1990, 1995

Project	1985			1990			1995		
	Production, bbl/ calendar day[a]	Emission factor, kg/10^3 bbl	Annual emissions, Mg	Production, bbl/ calendar day[a]	Emission factor, kg/10^3 bbl	Annual emission, Mg	Production, bbl/ calendar day[a]	Emission factor, kg/10^3 bbl	Annual emissions, Mg
Projects for which estimated emissions data were available									
Rio Blanco	45,000	173[b]	2,840	76,000	173[c]	4,800	135,000	173[c]	8,520
White River	--			--			90,000	301	9,890
Colony	38,400	61	855	46,200	61	1,030	46,200	61	1,030
Subtotal	83,400		3,695	122,200		5,830	271,200		19,440
Projects for which estimated emissions data were not available									
Cathedral Bluffs	30,000			200,000			200,000		
Union Oil	30,000			50,000			100,000		
Superior Oil	6,700			12,000			12,000		
Occidental[d]	--			--			--		
Geokenetics	15,000			50,000			50,000		
Naval Oil Reserve	--			28,000			50,000		
TOSCO, U-b	--			46,200			46,200		
Chevron	15,600			66,600			100,000		
Mobil	--			50,000			91,500		
Carter Oil	--			60,000			60,000		
Subtotal[d]	97,300		4,310	562,800		26,850	709,700		50,870
TOTAL	180,700		8,005	685,000		32,600	980,900		70,310

[a]Reference 19.
[b]Emissions estimated on assumption that average emission factors are the same as those for which emission data are available.
[c]Average of 104 and 242 kg/10^3 bbl.
[d]No data reported.

TABLE 5-9. ESTIMATED UNCONTROLLED SULFUR OXIDE EMISSIONS FROM PLANNED OIL SHALE DEVELOPMENT PROJECTS--1985, 1990, 1995

Project	1985			1990			1995		
	Production, bbl/ calendar day[a]	Emission factor, kg/10^3 bbl	Annual emissions, Mg	Production, bbl/ calendar day[a]	Emission factor, kg/10^3 bbl	Annual emissions, Mg	Production, bbl/ calendar day[a]	Emission factor, kg/10^3 bbl	Annual emissions, Mg
Projects for which estimated emissions data were available									
Rio Blanco	45,000	4,125[b]	67,750	76,000	4,125[b]	114,430	135,000	4,125[b]	203,260
Cathedral Bluffs	30,000	550	6,025	200,000	550	40,150	200,000	550	40,150
Colony	38,400	3,520[c]	49,335	46,200	3,520[c]	59,360	46,200	2,520[c]	59,360
Union Oil	30,000	1,633	17,880	50,000	1,633	29,800	100,000	1,633	59,605
Subtotal	143,400		140,990	372,200		243,740	481,200		362,375
Projects for which estimated emissions data were not available									
White River	--			--			90,000		
Superior Oil	6,700			12,000			12,000		
Occidental[d]	--			--			--		
Geokenetics	15,000			50,000			50,000		
Naval Oil Reserve	--			28,000			50,000		
TOSCO, U-b	--			46,200			46,200		
Chevron	15,600			66,600			100,000		
Mobil	--			50,000			91,500		
Carter Oil	--			60,000			60,000		
Subtotal[e]	37,300		36,675	312,800		204,840	499,700		376,305
TOTAL	180,700		177,665	685,000		448,580	980,900		738,680

[a]Reference 19.
[b]Average of 1,650 and 6,600 kg/10^3 bbl.
[c]Average of 2,640 and 4,400 kg/103 bbl.
[d]No data reported.
[e]Emissions estimated on assumption that average emission factors are the same as those for which emission data are available.

TABLE 5-10. ESTIMATED UNCONTROLLED NITROGEN OXIDE EMISSIONS FROM PLANNED OIL SHALE DEVELOPMENT PROJECTS--1985, 1990, 1995

Project	1985			1990			1995		
	Production, bbl/ calendar day[a]	Emission factor, kg/10^3 bbl	Annual emissions, Mg	Production, bbl/ calendar day[a]	Emission factor, kg/10^3 bbl	Annual emissions, Mg	Production, bbl/ calendar day[a]	Emission factor, kg/10^3 bbl	Annual emissions, Mg
Projects for which estimated emissions data were available									
Cathedral Bluffs	30,000	93	1,020	200,000	93	6,790	200,000	93	6,790
Subtotal	30,000		1,020	200,000		6,790	200,000		6,790
Projects for which estimated emissions data were not available									
Rio Blanco	45,000			76,000			135,000		
White River	--			--			90,000		
Colony	38,400			46,200			46,200		
Union Oil	30,000			50,000			100,000		
Superior Oil	6,700			12,000			12,000		
Occidental[b]	--			--			--		
Geokenetics	15,000			50,000			50,000		
Naval Oil Reserve	--			28,000			50,000		
TOSCO, U-b	--			46,200			46,200		
Chevron	15,600			66,600			100,000		
Mobil	--			50,000			91,500		
Carter Oil	--			60,000			60,000		
Subtotal[c]	150,700		5,125	485,000		16,465	780,900		26,510
TOTAL	180,700		6,145	685,000		23,255	980,900		33,300

[a]Reference 19.
[b]No data reported.
[c]Emissions estimated on assumption that average emission factors are the same as those for which emission data are available.

TABLE 5-11. ESTIMATED UNCONTROLLED HYDROCARBON EMISSIONS FROM PLANNED OIL SHALE DEVELOPMENT PROJECTS--1985, 1990, 1995

Project	1985			1990			1995		
	Production, bbl/calendar day[a]	Emission factor, kg/10^3bbl	Annual emissions, Mg	Production, bbl/calendar day[a]	Emission factor, kg/10^3bbl	Annual emissions, Mg	Production, bbl/calendar day[a]	Emission factor, kg/10^3bbl	Annual emissions, Mg
Projects for which estimated emissions data were available									
Rio Blanco	45,000	480	7,885	76,000	480	13,315	135,000	480	23,650
Cathedral Bluffs	30,000	60	655	200,000	60	4,380	200,000	60	4,380
White River	--			--			90,000	240	7,885
Colony	38,400	1,260	17,660	46,200	1,260	21,245	46,200	1,260	21,245
Union Oil	30,000	1,040	11,390	50,000	1,040	19,980	100,000	1,040	37,960
Superior Oil	6,700	3,980	9,735	12,000	3,980	17,430	12,000	3,980	17,430
Subtotal	150,100		47,325	384,200		76,350	583,200		112,550
Projects for which estimated emissions data were not available									
Occidental[b]	--			--			--		
Geokenetics	15,000			50,000			50,000		
Naval Oil Reserve	--			28,000			50,000		
TOSCO, U-b	--			46,200			46,200		
Chevron	15,600			66,600			100,000		
Mobil	--			50,000			91,500		
Carter Oil	--			60,000			60,000		
Subtotal[c]	30,600		9,650	300,800		59,775	397,700		76,750
TOTAL	180,700		56,975	685,000		136,125	980,900		189,300

[a]Reference 19.
[b]No data reported
[c]Emissions estimated on assumption that average emission factors are the same as those for which emission data are available.

TABLE 5-12. ESTIMATED UNCONTROLLED CARBON MONOXIDE EMISSIONS FROM PLANNED OIL SHALE DEVELOPMENT PROJECTS--1985, 1990, 1995

Project	1985			1990			1995		
	Production, bbl/calendar day[a]	Emission factor, kg/10^3bbl	Annual emissions, Mg	Production, bbl/calendar day[a]	Emission factor, kg/10^3bbl	Annual emissions, Mg	Production, bbl/calendar day[a]	Emission factor, kg/10^3bbl	Annual emissions, Mg
Projects for which estimated emissions data were available									
Cathedral Bluffs	30,000	320	3,505	200,000	320	23,360	200,000	320	23,360
White River	--	--	--	--	--	--	90,000	680	23,340
Colony	38,400	280	3,925	46,200	280	4,720	46,200	280	4,720
Union Oil	30,000	1,420	15,550	50,000	1,420	25,915	100,000	1,420	51,830
Superior Oil	6,700	880	2,150	12,000	880	3,855	12,000	880	3,855
Subtotal	105,100		25,130	308,200		57,850	448,200		107,105
Projects for which estimated emissions data were not available									
Rio Blanco	45,000			76,000			135,000		
Occidental[b]	--			--			--		
Geokenetics	15,000			50,000			50,000		
Naval Oil Reserve	--			28,000			50,000		
TOSCO, U-b	--			46,200			46,200		
Chevron	15,600			66,600			100,000		
Mobil	--			50,000			91,500		
Carter Oil	--			60,000			60,000		
Subtotal[c]	75,600		18,075	376,800		70,725	532,700		127,300
TOTAL	180,700		43,205	685,000		128,575	980,900		234,405

[a]Reference 13.
[b]No data reported.
[c]Emissions estimated on assumption that average emission factors are the same as those for which emission data are available.

will increase as shale oil projects are commercialized. It should also be noted that limitations on development by Prevention of Significant Deterioration (PSD) requirements were not in projected production levels. It is conceivable that PSD-allowable increments could be exhausted before production levels used in the emission estimates are achieved.

5.6 RECOMMENDATIONS

As noted in preceding sections, emission data for the oil shale industry are limited. The following actions should be taken to improve the data base to the level required for New Source Performance Standard (NSPS) development:

- Evaluation of basis for existing data, mode of acquisition, data quality, and data completeness.
- Filling of data gaps, as revealed by the evaluation.
- Characterization of emission streams and fugitive emissions resulting from each of the various surface and in situ retorting processes. Work may include acquiring data on size-dependent mass emissions (fine particles) as well as chemical characterization of such samples.

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6. EMISSION CONTROL TECHNOLOGY

6.1 INTRODUCTION

Oil shale processing involves numerous activities with emissions of environmental concern. To reduce emissions from an oil shale processing facility, appropriate pollution controls must be applied to processing steps at the potential emission source. The purpose of this chapter is to identify potential sources of pollutants and to identify and compare available pollution control techniques.

Based on the discussion in Section 4 of various oil shale processing options, Table 6-1 is a list of potential emissions as a function of processing activity. As shown, there are multiple sources of criteria pollutants in oil shale processing. The total potential emissions of a given pollutant are quite large because much raw shale is handled and processed to produce a barrel of shale oil and because sulfur and nitrogen concentrations in oil shale are relatively high compared to carbon concentration. While raw shale may contain up to 3 percent sulfur, typical shale from the Green River formation in Colorado, Utah, and Wyoming contains about 0.7 percent sulfur, of which one-third is organic.[1,2] During pyrolysis only a portion of the organic sulfur undergoes reaction; about 40 percent is released as sulfur species, primarily as hydrogen sulfide in shale oil gas. Thus, only about 12 percent of sulfur in raw shale evolves as a potential gaseous pollutant; most remains in shale oil and spent shale. This observation is also in agreement with data from the Paraho semi-works retort.[3]

The potential sulfur oxide emissions from use of the retort gas is estimated between 120 and 240 Mg/day (132 to 264 ton/day) for a 50,000 bbl/day facility (see Subsection 5.3.3).

In recent years various oil shale process developers, the U.S. Environmental Protection Agency (EPA), and the U.S. Department of Energy (DOE)

TABLE 6-1. SOURCES AND NATURE OF POTENTIAL ATMOSPHERIC EMISSIONS FROM OIL SHALE EXTRACTION AND PROCESSING

Process and activity	Potential criteria[a] pollutants	Potential noncriteria pollutants
Blasting	PM, CO, NO_x, HC	Hg, Pb salts, silica
Mine equipment (fuel use)	PM, CO, NO_x, SO_2, HC	
Preparation of retort feed[b]	PM	Silica
Retorting	PM, CO, NO_x, SO_2, HC	Trace elements and organics
Spent shale discharge[c]	PM, HC, CO, NO_x, SO_2	H_2S, NH_3, volatile compounds, trace metals (Ni, CO, Fe, Mo)
Upgrading[d]	PM, CO, NO_x, SO_2, HC	
Sulfur removal, retort off-gases	PM, CO, NO_x, SO_2, HC	CS_2, COS
Product storage	HC	
Equipment leakage pumps, valves, etc.	HC	

[a] PM = Particulate matter; HC = Hydrocarbons.
[b] Primary and secondary crushing and transport of raw shale.
[c] Includes all activities through final disposal.
[d] Includes all activities after discharge of oil from retorts.

have sought to characterize effluent streams from various in situ and surface retorts. For several reasons, however, few of these data may be of use to specify pollutant control devices:

- Many data have been collected on process development retorts used to collect process data and demonstrate technology. Retorting processes have not operated at commercial-scale, and retort performance has not been optimized with respect to maximizing oil production or minimizing pollutant generation. In most cases, data from in situ operations have been collected over only portions of the burn. In addition, most tests have been for special purposes, focusing on one or only a few of the gas stream components. Whole process data have been obtained for retort technologies, but they have in general been collected in isolation from gas stream tests.
- Analytical problems are numerous, and analysis techniques are in various stages of development. Problems include lack of appropriate standards for analyzing retorting products and difficulties in taking samples, in assuring samples represent the process, and in evaluating and/or quantifying interference among gas stream pollutants.
- The composition of retort effluents depends largely upon operating conditions and feed material composition. Because of wide variation in oil shale composition, retorting processes, and retort operations, samples taken for retorting operations and analyzed may be representative only of that sample.[4] Measurement and testing of off-gases from in situ retorts must be made over the entire burn to account for variations in elemental constituents within the deposit and possible short-term retention of organics in the retort.
- Very little work has been done on treating retort effluents with control devices. Most small-scale, pilot-plant product gases are flared without control. Rio Blanco has an installed flue gas desulfurization unit at the C-a Tract site, but few measurements other than for sulfur concentrations have been made on it.[5]

Uncertainties in the scale-up of retorting processes make selecting control options difficult and tenuous at best. It has been shown that gases

produced in direct-fired retorts are significantly different from gases normally encountered in applications of desulfurization technology.[6] High CO_2 levels and the high CO_2/H_2S ratios in these gases make many desulfurization technologies impractical. Since gases are produced in huge volumes at near atmospheric pressures, many other desulfurization process may not be economically applied. In addition, data for gas compositions are from pilot-plant and bench-scale operations. When processes are scaled-up, concentrations of gas components and trace elements may vary. However, as noted repeatedly by the literature, a number of control processes are available that have been commpercially proven in applications similar to potential applications in oil shale processing.[7,8,9,10,11,12]

Criteria pollutants--particulate matter, sulfur dioxide, nitrogen oxides, hydrocarbons, and carbon monoxide--will be of primary concern in oil shale processing, but certain noncriteria pollutants may also be of interest. However, paucity of hard data on characterization of emissions from oil shale processing, for reasons described above, does not permit identification or quantification of trace elements. Oil shale is generally retorted in surface retorts at temperatures from 430° C (810° F) to 540° C (1,000° F). At these temperatures, only elements with higher vapor pressure are volatilized, e.g., antimony, arsenic, boron, cadmium, lead, mercury, and selenium. These elements are reported to be in shale oil retort water and off-gas.[13] Another study suggests that mercury and arsenic constitute potential emission problems.[14] Temperature control problems encountered during in situ processing may result in excursions above 540° C (1,000° F), which could result in volatilization of some of the lower vapor pressure trace elements found in oil shale.

Subsequent subsections discuss sources of potential pollutants from oil shale processing and applicable control techniques.

6.2 CONTROL APPROACHES

As noted above, the literature contains several excellent discussions of pollutant control devices for oil shale processing. The material presented below borrows heavily from the draft volume 1 of the Pollution Control Guidance Document for Oil Shale.[7] This material is supplemented with material from other sources as indicated.

6.2.1 Particulate Matter Control

6.2.1.1 Particulate Matter Sources. Sources of particulate matter emissions from oil shale operations are discussed in Chapter 5. Particulate matter is produced during mining, processing, handling, and storage of raw and spent shale. In addition, considerable quantities of fine particulate matter are generated during retorting because of increased friability caused by heating shale.

6.2.1.2 Particulate Matter Control Options. Options for particulate control are shown in Figure 6-1. A description of each option and their advantages and disadvantages are given in Table 6-2. Particulate emission control at oil shale processing sites could include the following measures:[9]

- For surface mining:
  - Prewatering and wetting for dust control.
  - Treating mining area with dust palliatives such as oil emulsions, polymers, and soil stabilizers.
  - Restricting construction and mining vehicle activity.
- For underground mining:
  - Application of water and wetting agents during drilling.
  - Muck pile of blasted shale wetted before and during rock loading.
  - Conventional road wetting and chemical stabilization techniques use for haulage roads.
- For shale preparation:
  - Primary and secondary crushers enclosed with fabric filter dust collector baghouse.
  - Primary and secondary crusher units equipped with water sprays or dust collection systems followed by wet scrubbers.
  - Fully enclosed belts and dust collection followed by wet scrubbers at transfer points.

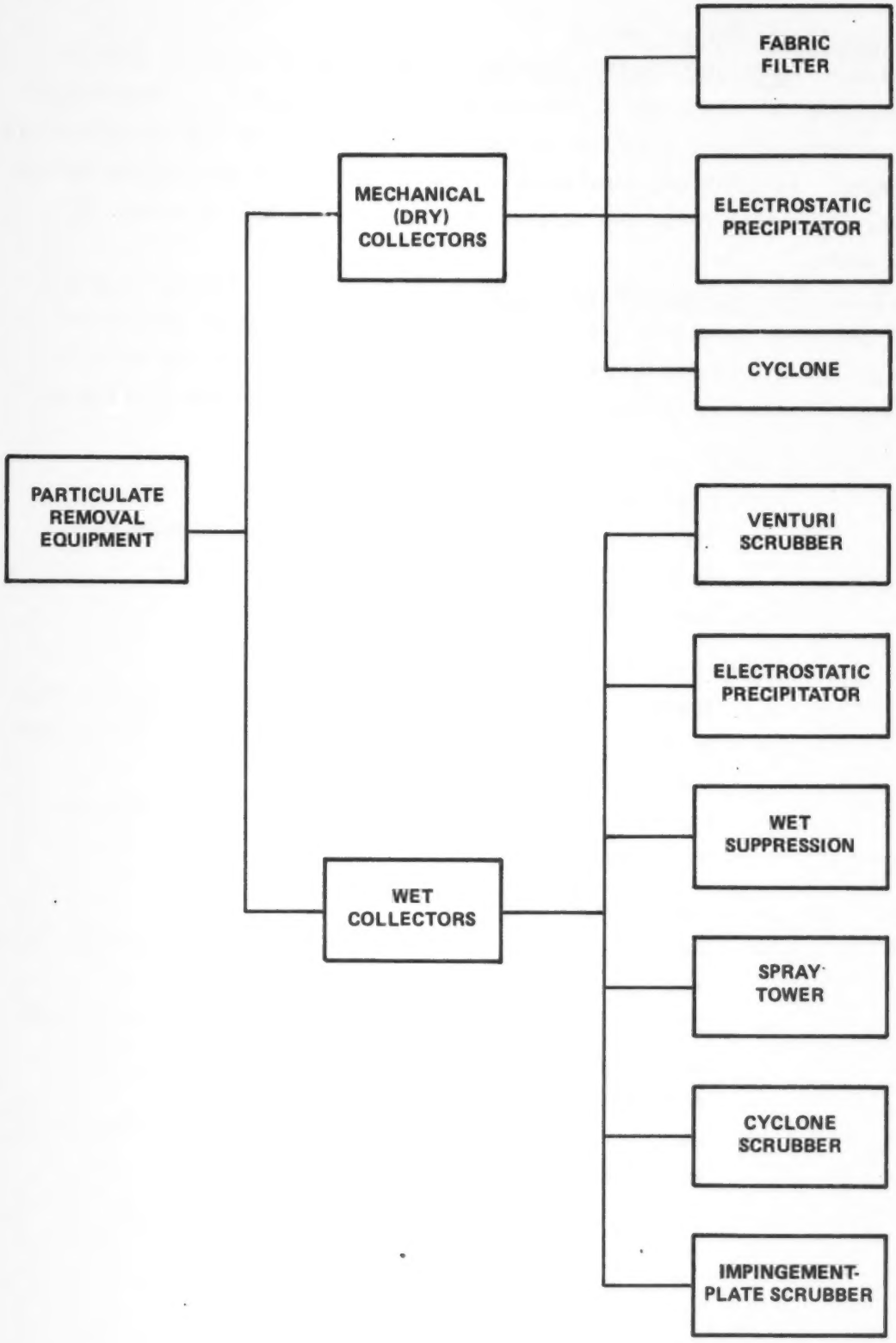

Figure 6-1. Particulate removal options.

TABLE 6-2. KEY FEATURES OF PARTICULATE MATTER REMOVAL SYSTEMS APPLICABLE TO OIL SHALE PROCESSES[7]

Mechanical (dry) collectors	Operating principle	Removal[a] efficiency (%)	Temperature limitations (°F)	Pressure drop ($IN.H_2O$)	Advantages	Disadvantages
Fabric filter	The dust-laden gas passes through woven fabric or felt material which filters out the dust, allowing the gas to pass on. The filters can be cleaned by mechanical shaking or by reverse jet compressed air flow.	99.7-99.9	500	5	High removal efficiency and low operating cost.	The fabric is usually sensitive to the gas humidity, velocity, and temperature.
Electrostatic precipitator	Particles suspended in a gas are exposed to gas ions in an electro-static field. These particles then became charged and migrate under the action of the field to collector plates.	99-99.9	850	1	High removal efficiency and a very low pressure drop.	High relative energy consumption. Sensitivie to varying conditions and particle properties.
Cyclone	The dust-laden gas enters a cylindrical or conical chamber tangentially at one or more points and leaves through a central openings. The dust particles, because of their inertia, will tend to move toward the outside separator wall from which they are led into a receiver.	50-90	10,000	1-5	Low capital and operating cost. Very good as a gas precleaner before a more efficient removal device.	Low removal efficiency. Not effective on particle size below 10.
Venturi scrubber	Gas and liquid are passed cocurrently through a Venturi throat at 200 to 800 Ft./sec.	95-99	40-700	1-50	High removal efficiency.	High pressure drop and, therefore, high energy requirements.
Wet suppression	Fugitive dust generated in the crushing and handling of the oil shale is sprayed with a foam suppressant made from a water/ surfactant mixture.	95-99 ~80[b]	40-200	---	Low capital and operating cost and a high removal efficiency.	Not applicable to stack gases (used for conveyor transfer points, and crushing and grinding operations).

[a] Based on performance in industries other than oil shale.
[b] Efficiency of water sprays without wetting agents is about 80 percent for particle diameter greater than 5μ.[8]

(Continued)

TABLE 6-2. KEY FEATURES OF PARTICULATE MATTER REMOVAL SYSTEMS APPLICABLE TO OIL SHALE PROCESSES[7] (Continued)

Mechanical (dry) collectors	Operating principle	Removal[a] efficiency (%)	Temperature limitations (°F)	Pressure drop (IN.H_2O)	Advantages	Disadvantages
Impingement-plate scrubber	A perforated tray with an impinge-ment baffle above each perforation. The high gas velocity through the perforations atomizes the liquid on the tray into droplets which collect the dust by impaction. This operating principle is similar to that of a venturi scrubber.	80-99	40-700	1-20	High removal efficiency.	High removal efficiency requires high pressure drop and, therefore, high energy requirements.
Cyclone scrubber	Liquid is sprayed into a spinning gas stream and removes dust by inertial impaction.	50-75	40-700	2	Low pressure drop and low operating cost.	Low removal efficiency.
Spray tower	Liquid droplets produced by spray nozzles settle through rising gas stream and remove dust by impaction.	50-80	40-700	0.5	Low pressure drop and low operating cost.	Low removal efficiency.

[a] Based on performance in industries other than oil shale.
[b] Efficiency of water sprays without wetting agents is about 80 percent for particle diameter greater than 5μ.[8]

- Dust collected from baghouse slurries recycled to the retort shale moisturizer.
- Conveyor transfer points equipped with dust suppression systems.

- For shale retorting and refining:
  - Purified gas used to minimize particulate emission.
  - High energy venturi scrubber used to remove entrained shale dust in flue gas and vapors from shale moisturizing system.
  - Vent gas from feed hoppers and spent shale moisturizers collected and scrubbed to remove dust.

- For spent shale disposal:
  - Processed shale dumped, spread, and compacted in disposal areas to form a stable disposal pile.
  - Processes shale kept at a moisture content of 11 to 19 percent by adding water to aid compaction and stabilization.

Since particulate control techniques are physical rather than chemical, no problems are foreseen in applying them in other areas of oil shale processing.

6.2.2 Sulfur Emissions Control

6.2.2.1 Sources of Sulfur Emissions. The primary source of sulfur emissions from shale processing sites, if uncontrolled, would be in the form of sulfur dioxide. Sulfur dioxide is the principal sulfur specie produced by the combustion of sulfur-containing compounds such as hydrogen sulfide, carbonyl sulfide, carbon disulfide, mercaptains, and thiophene. These compounds are produced in the reducing environment of the retort. Sulfur species of higher molecular weight are also formed, but these tend to collect in product oil. Thus, using product oil or retort gas to produce process heat, steam, and power may create sulfur dioxide emissions. Because of their potential effect on human health and welfare and on vegetation, sulfur dioxide emissions are controlled by Federal and State regulations.

6.2.2.2 Sulfur Emissions Control Options. Sulfur compounds in retort off-gases are an air pollution problem when the gas is used in a combustion unit to generate process heat, steam, or electricity or is flared to the atmosphere. Two general options exist for controlling sulfur emissions under these circumstances: stack gas sulfur removal (flue gas desulfurization) after combustion and sulfur removal prior to combustion or flares. In the first option, sulfur species contained primarily in the retort gas are converted to sulfur dioxide by ordinary combustion of fuel gas. The resulting flue gas is scrubbed to remove sulfur dioxide. Processes commonly used or under development for flue gas desulfurization are outlined in Figure 6-2, and a brief description of the characteristics of each is given in Table 6-3. The second sulfur control option, where sulfur (primarily hydrogen sulfide) compounds are removed from the retort gas prior to combustion, can potentially be performed by several processes. These processes are outlined in Figure 6-3. A brief description of the characteristics of these systems and their advantages and disadvantages are given in Table 6-4.

Transferring flue gas desulfurization technology to the developing oil shale industry may present some difficulties. Because retort gas will be combusted prior to flue gas desulfurization, only a few major compounds will be present in these systems. These compounds should be qualitatively similar to components contained in flue gas produced in coal-fired boilers. Some adjustments may be needed in the processes to account for quantitative differences in the two flue gases and might entail a testing effort on a pilot-plant scale. However, Rio Blanco has used a sodium carbonate scrubber at Tract C-a to scrub flue gas produced during the burn of Retort Zero.[5]

Transferring hydrogen sulfide removal technology to reduce sulfur emissions from oil shale processing facilities may also present some difficulties, especially if the retort gases contain significant amounts of sulfur species other than hydrogen sulfide. One process, sulfiban, has been demonstrated to remove both hydrogen sulfide and organic sulfur compounds in coke oven by-product plants, but it has not been demonstrated in oil shale facilities. Another potential problem area could be trace components in retort gas; these components could disrupt the chemistry of the hydrogen sulfide removal processes. For example, Union Oil Company has used the

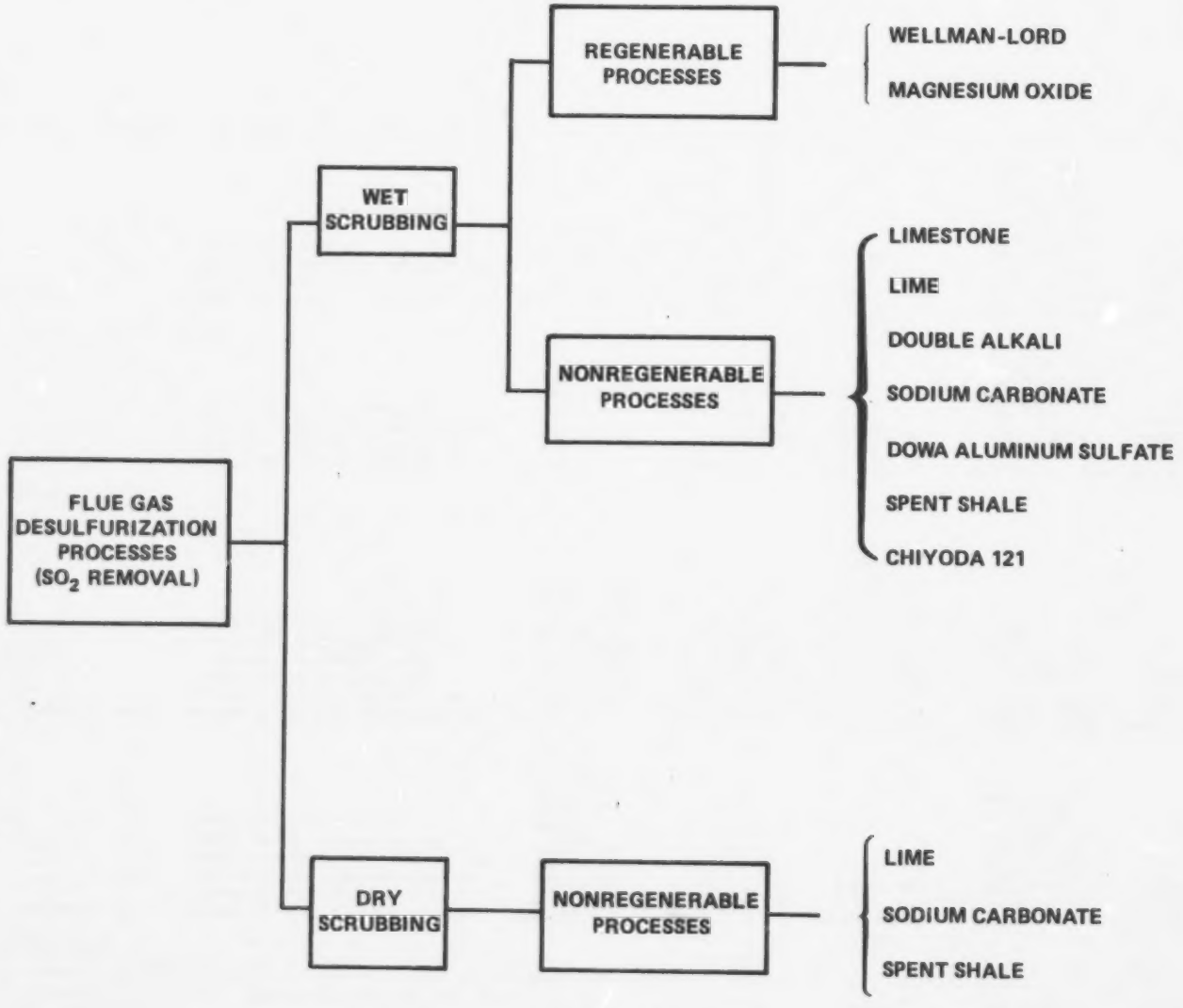

Figure 6-2. Flue gas desulfurization processes (SO_2 removal).

TABLE 6-3. KEY FEATURES OF FLUE GAS DESULFURIZATION SYSTEMS APPLICABLE TO OIL SHALE PROCESSES

Wet scrubbing process	Process description	Product/ Waste	Performance	Development status	Advantages	Disadvantages
Regenerable						
Wellman-Lord	Absorbs SO_2 with a sodium sulfite/ bisulfite solution. A bleed stream of the spend solution is sent to evaporators where SO_2 and water are driven off and the solution is regenerated.	Concentrated SO_2 stream (up to 90% SO_2 and 10% H_2O) suitable for sulfur or sulfuric acid manufacture.	Capable of reducing the outlet flue gas SO_2 concentration to 50 ppm.	Seven commercial unit are in operation.	Produces a concentrated SO_2 stream which can be used to make saleable sulfur or sulfuric acid.	Requires fuel for solution evaporators.
Magnesium oxide	Absorbs SO_2 with a magnesium oxide slurry. A bleed stream of the spent slurry is dried and calcined to regenerate the magnesium oxide and produce a dilute SO_2 stream (10% SO_2).	Produces a dilute SO_2 stream (10% SO_2) which is suitable for production of sulfuric acid.	Capable of reducing the outlet flue gas SO_2 concentration to 50 ppm.	Three demonstration plants have been tested (each about 100 MW size). Two commercial units are under construction.	Produces an SO_2 stream suitable for manufacture of sulfuric acid.	Requires fuel for the $MgSO_3/MgSO_4$ dryer and calciner.
Nonregenerable						
Limestone	Absorbs SO_2 with a limestone slurry. A bleed stream of the slurry is partially dewatered and disposed of in a landfill.	A slurry of hydrated calcium sulfite/ sulfate solids.	Capable of reducing the outlet flue gas SO_2 concentration to 50 ppm.	Many commercial units in operation.	Low capital and operating cost. Simple and proven process with conventional process equipment.	Has a low operability factor due to scalling, erosion, and corrosion.
Lime	Absorbs SO_2 with a lime slurry. A bleed stream of the slurry is partially dewatered and disposed of in a landfill.	A slurry of hydrated calcium sulfite/sulfate solids.	Capable of reducing the outlet flue gas SO_2 concentration to 50 ppm.	Many commercial units in operation.	Very similar to the limestone process and can potentially give greater SO_2 removal efficiency than limestone.	Lime costs are rising rapidly because of higher energy costs.

(Continued)

TABLE 6-3. KEY FEATURES OF FLUE GAS DESULFURIZATION SYSTEMS APPLICABLE TO OIL SHALE PROCESSES (Continued)

Wet scrubbing process	Process description	Product/ Waste	Performance	Development status	Advantages	Disadvantages
Nonregenerable						
Double alkali	Absorbs SO_2 with a dilute or concentrated sodium sulfite solution. The spent solution is regenerated by lime addition. The precipitated calcium sulfite/ sulfate solids are partially dwatered and disposed of in a landfill.	A slurry of hydrated calcium sulfite/ sulfate solids.	Capable of reducing the outlet flue gas SO_2 concentration to 50 ppm. Has been demonstrated to reduce SO_2 concentration to below 50 ppm on pilot plant scale.	Three commercial units in oepration.	Low in capital and operating cost like the limestone system but the use of a clear scrubbing solution reduces scalling erosion, and corrosion in the scrubbing loop.	Requires soda ash (Na_2CO_3) makeup in addition to lime for precipitation. Soda ash is an expensive raw material. The sludge contains soluble and leachable sodium salts.
Sodium carbonate	Absorbs SO_2 with a sodium carbonate solution. A bleed stream of the spent solution is partially dewatered and disposed of in a landfill.	Sodium sulfite/ sulfate sludge.	Capable of reducing the outlet flue gas SO_2 concentration to 50 ppm.	Four commercial units in operation.	Low capital cost. A very simple and reliable process.	Soda ash is an expensive raw material. Produces a sludge which is very difficult to dewater and dispose of.
Dowa aluminum sulfate	Absorbs SO_2 with an acidic clear solution of basic aluminum sulfate. The spent solution is forced oxidized to aluminum sulfate. Limestone is added to the solution to regenerate basic aluminum sulfate and produce gypsum which is partially dewatered and disposed of in a landfill.	A gypsum (hydrated calcium sulfate) slurry.	Capable of reducing the outlet flue gas SO_2 concentration to 50 ppm.		Uses the same basic process design as the double alkali process, and therefore, has the same advantages; the process uses a clear scrubbing solution which reduces scaling, erosion, and corrosion in the scrubbing loop.	

(Continued)

TABLE 6-3. KEY FEATURES OF FLUE GAS DESULFURIZATION SYSTEMS APPLICABLE TO OIL SHALE PROCESSES (Continued)

Wet scrubbing process	Process description	Product/ Waste	Performance	Development status	Advantages	Disadvantages
Nonregenerable						
Spent shale	Absorbs SO_2 with a spent shale slurry. A bleed stream of the slurry is partially dewatered and disposed of in a landfill.	Spent shale sludge.	Probably capable of reducing the outlet flue gas SO_2 centration to about 50 ppm.	The process is only conceptual at this time and has not been tested on a pilot plant scale.	Low capital and operating cost. Also, an abundant supply of spent shale is available at the plant site.	Has not yet been tested even on a pilot plant scale.
Chiyoda CT-121	The flue gas is first quenched to its saturation temperature and then sparged into a limestone slurry generating a jet bubbling froth layer. The SO_2 in the flue gas is absorbed by the limestone slurry in the jet bubbling layer. The calcium sulfite formed by this reaction is oxidized to calcium sulfate (gypsum) by the introduction of air into the jet bubbling layer. A bleed stream of the waste slurry can be dewatered and land-filled as a recoverable resource or given away to local cement, fertilizer, or wall board industries.	A gypsum (hydrated calcium sulfate) slurry.	Capable of reducing the outlet flue gas SO_2 concentration to 50 ppm.	The process has been tested on a demonstration size scale.	Absorbs SO_2 and oxidizes calcium sulfite to gypsum in one reator vessel.	Has only been tested on a demonstration size scale.
Lime	Flue gas is contacted with an atomized lime slurry in a spray dryer scrubber. The lime absorbs the SO_2, is dried, and then collected in a baghouse or electrostatic precipitator (ESP).	Dry calcium sulfite/ sulfate.	Capable of reducing the outlet flue gas SO_2 concentration to between 100 to 150 ppm.	The process has been tested on a demonstration size scale. Three commercial size units are currently under construction.	Since the flue gas is not saturated, slightly less makeup water is needed and less stack gas reheat is needed.	This system is usually only economically feasible where low sulfur fuel is burned because of the low reagent utilization rate. Very high removal efficiencies are also not usually possible because of the low reagent utilization rate.

(Continued)

TABLE 6-3. KEY FEATURES OF FLUE GAS DESULFURIZATION SYSTEMS APPLICABLE TO OIL SHALE PROCESSES (Continued)

Wet scrubbing process	Process description	Product/ Waste	Performance	Development status	Advantages	Disadvantages
Nonregenerable						
Sodium carbonate	Flue gas is contacted with an atomized solution of aqueous sodium carbonate in a spray dryer scrubber. The sodium carbonate absorbs the SO_2, is dried, and then collected in a baghouse or electrostatic precipitator (ESP.)	Dry sodium sulfite/ sulfate.	Capable of reducing the outlet flue gas SO_2 concentration to between 75 to 100 ppm.	The process has been tested on a demonstration size scale.	Same as for lime dry scrubbing process.	Same as for the lime dry scrubbing process. Also, soda ash is an expensive raw material.
Spent shale	Flue gas is contacted with an atomized spent shale slurry in a spray dryer scrubber. The alkaline minerals in the spent shale (primarily calcium carbonate) absorbs the SO_2, is dried, and then collected in a baghouse or electrostatic precipitator (ESP).	Dry spent shale.	Probably capable of reducing the outlet flue gas SO_2 concentration to between 100 to 150 ppm.	The process is only conceptual at this time and has not been tested on a pilot plant scale, but the Lurgi oil shale retorting process lift pipe and flue gas treating equipment closely resembles this system.	Same as for the lime dry scrubbing process. Also, an abundant supply of spent shale is available at the plant site.	Same as for the lime dry scrubbing process.

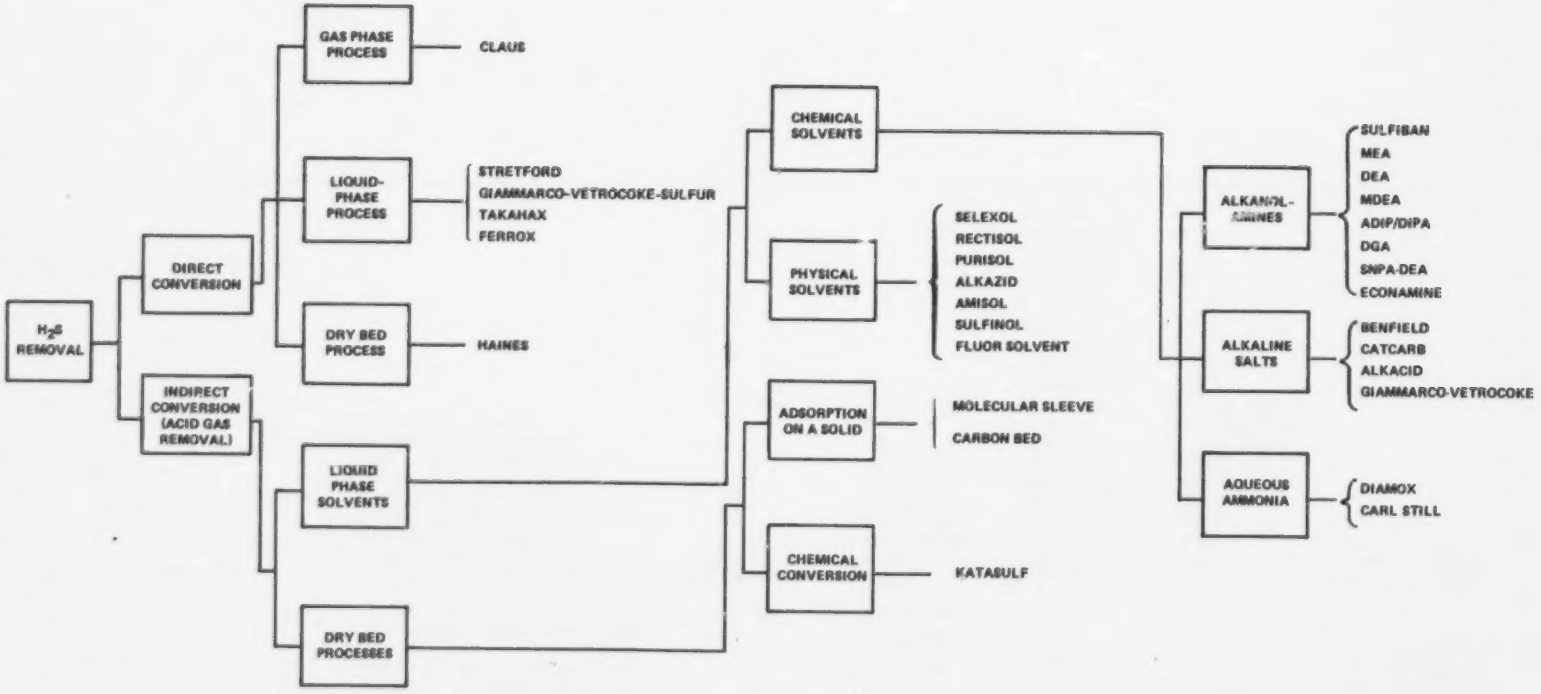

Figure 6-3. H_2S removal process.

TABLE 6-4. COMPARISON OF SULFUR REMOVAL SYSTEMS APPLICABLE TO OIL SHALE PROCESSES[7]

Control technique	Process	Process principle	Components removed	Performance	Selectivity	Commercial availability	Advantages	Disadvantages
Direct conversion	CLAUS	Partial oxidation of H_2S to SO_2 and subsequent reaction $2H_2S + SO_2 \rightarrow S + 2H_2O$ in gas phase.	H_2S + other sulfur compounds.	95% H_2S 33% (others).	Side reactions with CO_2 and light hydrocarbons result in stable sulfur compounds emitted from the process.	Continuously improved designs available.	-Provides extremely good quality elemental sulfur.	-Often not adequate to control sulfur compound air pollution.
Direct conversion	STRETFORD	H_2S absorption and liquid-phase oxidation $H_2S + O_2 + S + H_2O$ in an alkaline solution of a vanadium salt.	H_2S	< 100 ppm	CO_2 absorbed in the process reduces sulfur removal efficiency causing significant increases in absorber height requirements.	Process currently available for disposal of waste streams from Stretford units.	-Process suitable for desulfurization of a variety of gas streams.	-HGN in feed produces a non-regenerable compound with high pollution potential.
Direct conversion	GIAMMARCO-VETROCOKE	H_2S absorption and liquid-phase oxidation $H_2S + O_2 + S + H_2O$ in a solution of arsenic salt.	H_2S COS CS_2	99.99%	High selectivity for H_2S.	Available for desulfurization of coke-oven and synthens gases and natural gas.	-Capable of producing purified gas containing less than 1 ppm H_2S even at temperatures up to 300 F.	-Hazardous nature of arsenic solution.
Direct conversion	TAKAHAX	H_2S absorption and liquid-phase oxidation $H_2S + O_2 + S + H_2O$ in an alkaline solution of naphthoquinone compounds.	H_2S	99.99%	High selectivity for H_2S.	100+ units operating in Japan.	Capable of producing treated gas containing no detectable H_2S even at high inlet concentrations.	Sulfur precipitation is of very fine grain and amenable to removal via flotation techniques.

(Continued)

TABLE 6-4. COMPARISON OF SULFUR REMOVAL SYSTEMS APPLICABLE TO OIL SHALE PROCESSES[7] (Continued)

Control technique	Process	Process principle	Components removed	Performance	Selectivity	Commercial availability	Advantages	Disadvantages
Direct conversion	FERROX	H_2S absorption and liquid-phase oxidation $H_2S + O_2 \rightarrow S + H_2O$ in a solution of $NaCO_2$ and FeOH.	H_2S	85-99%	Good selectivity for H_2S.	Few ferrox plants are still in operation.	Marked improvements over dry-box purification due to reduced installation and labor costs.	: Sulfur from the ferrox process is not suitable for most uses and chemical replacement costs are high.
Direct conversion	HAINES	Molecular sieves remove H_2S and water. H_2S is stripped from the bed and reacted with SO_2 to form elemental.	H_2S H_2O	< 0.25 grains H_2S per 100 SCF		Pilot plants in operation in Canada. Extended operation of full-scale plant unknown.		Zeolite adsorption beds may become fouled impairing regeneration.
Indirect conversion	SULFIBAN	Absorption into an alkanolamine solution.	H_2S RSH	< 1grains H_2S per 100 SCF	Good for H_2S RSH.	Demonstrated on coke oven by-products plants.	Removes both H_2S and RSH reliably.	
Indirect conversion	MEA	H_2S and CO_2 absorbed by a regenerable reaction with monoethanolamine at ambient temperatures.	H_2S CO_2		Preferred solvent for gas streams with low concentrations of H_2S and CO_2 and essentially no minor contaminants (e.g., COS, CS_2).	Used almost exclusively for years to remove H_2S and CO_2 from natural and certain synthesis gases.	-MEA + Used predominantly in the gas sweetening industry. -CO_2 and CS_2 form products.	-Non H_2S selective (i.e. CO_2 also absorbed). -Reacts irreversibly with COS, CS_2.
Indirect conversion	MDEA	Selective absorption of H_2S by a regenerable reaction with Methyldiethanolamine.						

(Continued)

TABLE 6-4. COMPARISON OF SULFUR REMOVAL SYSTEMS APPLICABLE TO OIL SHALE PROCESSES[7] (Continued)

Control technique	Process	Process principle	Components removed	Performance	Selectivity	Commercial availability	Advantages	Disadvantages
Indirect conversion	ADIP/DIPA	Selective absorption of H_2S by a regenerable reaction with Dilsopropylamine.	H_2S CO_2		Used commercially as a selective H_2S solvent for Claus plant tail gas purification.		-Substantial amounts of COS removed without detrimental effects. -Low regeneration steam requirements.	
Indirect conversion	DGA/ Economine	Absorption of H_2S by a regenerable reaction with Diglycola-Diglycolamine.	H_2S CO	< 0.25 grains H_2S/100 SCF		Sour gas processing in its operation.	-DGA similar to MEA with lower vapor pressure. -Lower circulation rates and consumption than MEA.	-DGA costs are high. -High corrosivity. -Losses due to reaction with CO_2, COS, CS_2 are high. -Reclaiming requires vacuum distillation.
Indirect conversion	ALKAZID	Process uses various proprietary absorption characteristics of ammonia with total (0.7 wt% NH_3) liquid recycle.	H_2S CO_2		Capable of selective removal of H_2S when correct absorption solution is used.	Although operated abroad since the 1930's no commercial installations are known in the USA.	-Solutions are relatively noncorrosive. -Solution tailored to requirements for H_2S selectivity and to minimize effect of contaminants.	

(Continued)

TABLE 6-4. COMPARISON OF SULFUR REMOVAL SYSTEMS APPLICABLE TO OIL SHALE PROCESSES[7] (Continued)

Control technique	Process	Process principle	Components removed	Performance	Selectivity	Commercial availability	Advantages	Disadvantages
Indirect conversion	DIAMOX	Selective H_2S removal process using absorption characteristics of ammonia with total (0.7 wt% NH_3) liquid recycle.	H_2S	Can achieve 8 grains. H_2S/100 SCF	Selectively removes H_2S.	Recently developed and commercialized in Japan.	-Acid gas produced is suitable Claus feed or sulfuric acid plant feed. -Low pressure process.	Purge stream of ammonia liquor produced.
Indirect conversion	CARL STILL	Selective H_2S removal process using ammonia for absorption (2.0 wt% NH_3) with total liquid recycle.	H_2S	Can achieve 50 grains. H_2S/100 SCF	Selectively removes H_2S.	Commercial process now in operation in USA.	-Low pressure process. -Good Claus plant feed.	-H_2S selectivit less than DIAMOX. -Concentrated NH_3 solutions highly corrosive.
Indirect conversion	SELEXOL	Uses an anhydrous organic solvent dimethylether of polyethylene glycol which physically dissolves acid gases and is stripped by reducing pressure without adding heat.	H_2S CO_2 RSH COS	< 1 ppm.	H_2S very soluble in selexol solvent.	Few plants in operation for natural gas treatment and for synthesis and coal-derived gas purification.	-Non-toxic solvent.	-Requires high partial pressure of acid gas.
Indirect conversion	FLUOR SOLVENT	Uses an anhydrous organic solvent proprylene carbonate which physically dissolves acid gases.	CO_2 H_2S			Plants in operation for CO_2 only gases and combination CO_2, H_2S gases.	-Low operating costs.	-Solvent intended primarily for removal of CO_2.

(Continued)

TABLE 6-4. COMPARISON OF SULFUR REMOVAL SYSTEMS APPLICABLE TO OIL SHALE PROCESSES[7] (Continued)

Control technique	Process	Process principle	Components removed	Performance	Selectivity	Commercial availability	Advantages	Disadvantages
Indirect conversion	MOLECULAR SIEVE	Use of molecular sieves to adsorb sulfur compounds.	H_2O CO_2 H_2S SO_2 NH_2 COS, RSH	Very effective.		-Not widely used for removing H_2S from gas streams.	-Extended useful life (3-5 years) of adsorbent possible with properly designed molecular sieve.	-Preferably used on high pressure streams. -Regeneration gas disposal.
Indirect conversion	CARBON BED	Activated carbon beds used to catalytically oxidizes H_2S to elemental sulfur at ambient temperatures. Sulfur removed by solvent washing.	H_2S	Concentrations greater than approximately 400 grains per 100 SCF difficult to treat satisfactory without recycling purified gas or by cooling the bed.		Not applied on a large commercial scale.	-Very pure sulfur obtained. -Complete H_2S removal.	-Carbon deactivated rapidly. -Purification required to remove tar and ammonia. -Complicated sulfur extration procedure. -1500 ppm/H_2S limit in feed.
Indirect conversion	KATASULF	Air and preheated gas w/H_2S catalyzed to form SO_2, which is absorbed in an aqueous ammonium sulfite-bisulfite solution.	H_2S NH_3	< 4 ppm H_2S		Large commercial units in operation.	-Produces a saleable ammonium sulfate.	Carbon-steel corrosion problems exist with some forms of the process.

TABLE 6-4. COMPARISON OF SULFUR REMOVAL SYSTEMS APPLICABLE TO OIL SHALE PROCESSES[7] (Continued)

Control technique	Process	Process principle	Components removed	Performance	Selectivity	Commercial availability	Advantages	Disadvantages
Indirect conversion	PURISOL	Uses an anhydrous organic solvent N-methyl-2-pyrolidine which physically dissolves acid gases.	H_2S CO_2 RSH COS	< 3 ppm H_2S	Exceptionally high solubility.	Four commercial installations in operation as of 1979.	Highly H_2S selective.	
Indirect conversion	SULFINOL	Uses a mixture of chemical (DIPA) and physical solvent (sulfolane) and water.	H_2S COS RSH CO_2	96-99%		Wide application in the treatment of natural, refinery, and synthesis gases.	-Removes COS, RSH. -Capacity is high at partial pressure of H_2S.	-Optimum operation under high pressure. -Solution absorbs heavy HC's requiring flash tank separation.
Indirect conversion	AMISOL	Uses a mixture of a chemical (MEA/DEA) and a physical solvent (Methanol).	All sulfurs CO_2	< 0.1 ppm < 5 ppm		Only semi-commercial plants in operation.	-Capable of removing all sulfur.	
Indirect conversion	RECTISOL	Uses physical absorbtion in methanol at low temperature.	H_2S CO_2 COS, CS_2 RSH HCN HC's	No detectable H_2S possible.	Considerably higher solubility of H_2S over CO_2.	Large industrial plant in operation.	-Heat input low because temperature maintained by flashing. -Removes all undesirable components in single step.	-Complex operation. -High solvent losses. -Best suited for higher pressures. -Low temperature process.

(Continued)

treating the off-gas from a laboratory-sized retort[8] and has found sulfur produced by the processes to be contaminated by charred hydrocarbons, which lower the resale value of the recovered sulfur. Union also expressed an interest in the chemistry of the Stretford solution, indicating that they were not entirely satisfied with the performance of the standard materials.

6.2.3 Nitrogen Oxide Emissions Control

6.2.3.1 Nitrogen Oxide Sources. Oxides of nitrogen (NO_x) are a natural product of the combustion of conventional fuels and may be a significant air pollution emission from oil shale processing. The major source of potential NO_x emissions during oil shale processing will be from the combustion of nitrogen-containing fuels, in which high yields of nitrogen to NO_x will be achieved, or from fixation of molecular nitrogen from combustion air in high-temperature combustion processes. NO_x emissions contribute to secondary chemical reactions in the atmosphere, resulting in formation of photochemical oxidants, and are in themselves undesirable from a physiological point of view.[8] Conditions in or near the flame in industrial combustion units are such that the nitrogen in the combustion air is converted to NO_x. In addition, oxidation of chemically bound nitrogen in shale oil off-gases, e.g., NH_3, also results in NO_x formation.

6.2.3.2 Control Options for NO_x Control. Nitrogen compounds in retort off-gas do not in themselves present an air pollution problem. However, problems do arise with these gases when used in a combustion unit to generate process heat, steam, or electricity or when flared to the atmosphere. As shown in Figure 6-4, the options available for reducing the potential NO_x emissions from an oil shale retorting facility are combustion modification, fuel-nitrogen removal, and stack gas removal of NO_x. Table 6-5 describes characteristics, advantages, and disadvantages of NO_x control options applicable to oil shale processing.

Because the oil shale industry is still in the pilot-plant phase, it is still in a position to design furnaces with low NO_x emissions into their commercial-scale units.[8] This may be more cost effective than retrofit control devices. Combustion system modifications may not by themselves meet the required control of NO_x emissions, in which case appropriate retrofit control systems could be added to the shale retorting facility to meet emission requirements.

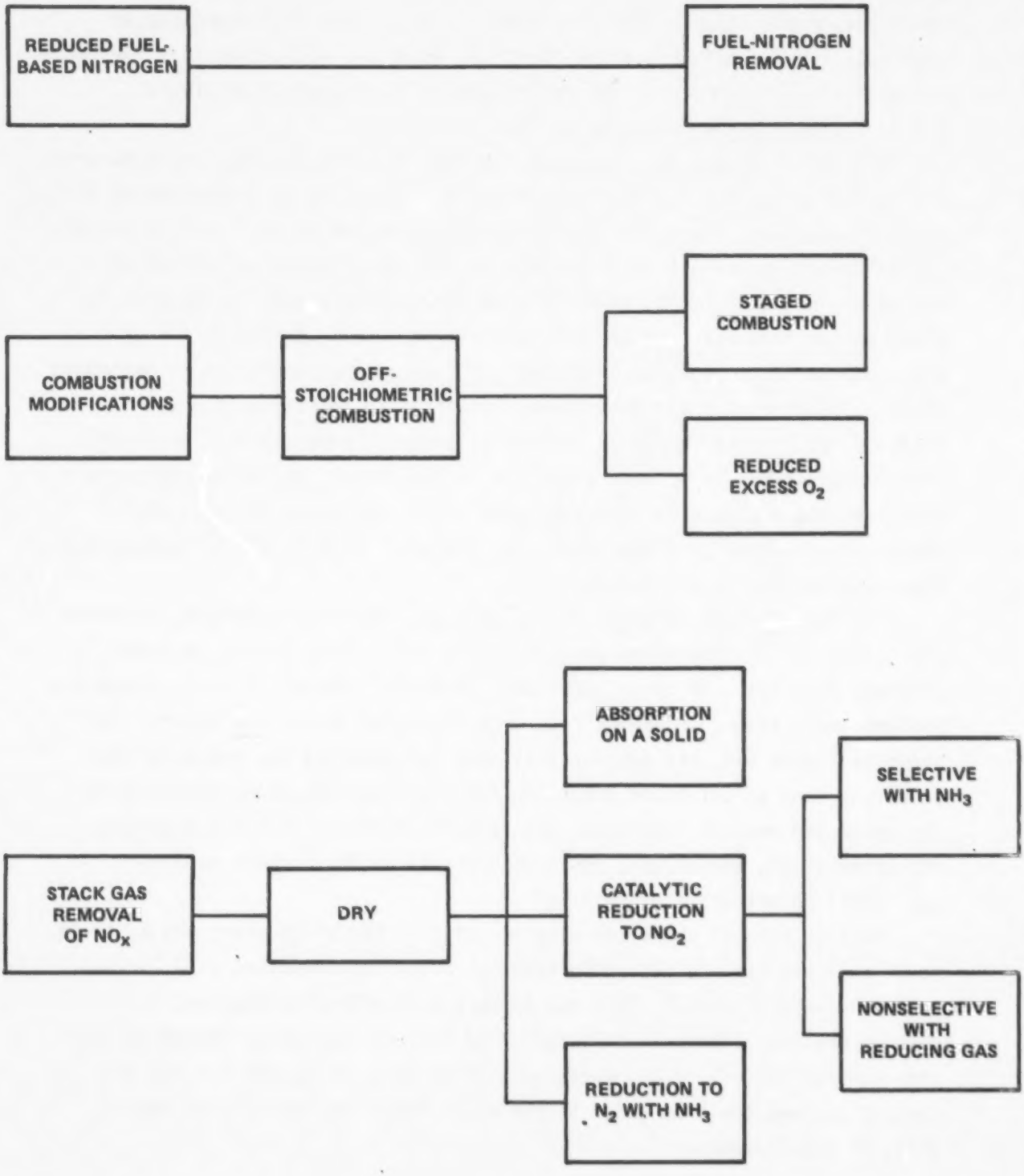

Figure 6-4. Technologies for the reduction of NO_x in stack gas emissions.

TABLE 6-5. COMPARISON OF NO_X CONTROL SYSTEMS APPLICABLE TO OIL SHALE PROCESSES

Control method	Process	Process description	Performance	Development status	Advantages	Disadvantages
Fuel nitrogen removal	NH_3 Scrubbing	Absorption of NH_3 by counter-current scrubbing with water.	Up to 100% of NH_3 removal possible by changing water; rate, composition, and temperature.	Commercially proven.	Removes source of NO_X before formed. Byproduct NH_3 produced	-Does not reduce NO_X emissions formed by thermal fixation of oxygen in combustion air.
Combustion modifications	Two-Stage Combustion (either low-emission burners or engineered combustion box).	Air is introduced in two zones. Zone 1) combustion occurs under reducing conditions, Zone 2) additional air added to complete combustion.	40-60% of thermal NO_X reduction. Less reduction for fuel-nitrogen.	Burners and boiler designs commercially available.	Burner system inexpensive in relation to total cost.	-Reducing zone can cause boiler tube damage.
	Low-Excess Air	Reduce excess air available to reduce reaction Kinetics of N-radial & O_2 reaction.	10-20% NO_X reduction.		Require only operational changes.	-Boiler more difficult to operate, possible increase in CO/HC emissions.
Stack gas removal of NO_X	Selective Catalytic Reduction (SCR)	NO_X reduced by NH_3 over a catalyst (all processes similar using various proprietary catalysts).	90% NO_X removal.	4 processes in commercial scale operation. 20 processes available.	-Commercially demonstrated.	Particulates and SO_2 can cause catalyst plugging and poisoning.
Stack gas removal of NO_X	Thermal DeNO$_X$	NY_2 injected in a 1300-1800 F flame zone where NO + NH_3 + N_2 + H_2O.	70% NO_X removal.	Demonstrated commercially.	-NO byproduct recovery required. -Low capital cost.	-Requires large amounts of NH_3. -Narrow operating range.

In addition, due to the high conversion rate for ammonia to NO_x, NH_3 removal before combustion may be a reasonable control option. The volume of fuel requiring treatment at this stage is much smaller than the eventual volume of flue gas. Also, process equipment used for cooling and NH_3 absorption should produce a light oil product. The value of this product may be sufficient to offset much of the cost of the NH_3 removal facilities.

6.2.4 Hydrocarbon and Carbon Monoxide Emissions Control

6.2.4.1 Sources of Hydrocarbon and Carbon Monoxide Emissions. Hydrocarbons may be emitted to the atmosphere at oil shale processing facilities as a result of incomplete retort gas combustion or as fugitive emissions from leaks in processing facilities or oil storage equipment. Carbon monoxide is usually formed by incomplete combustion of fuels. Normally excess oxygen is supplied to a combustion process to ensure that all of fuel carbon is converted to carbon dioxide. When an oxygen shortage occurs in the combustion process, some carbon is only partially oxidized to carbon monoxide.

6.2.4.2 Control Options for Hydrocarbon and Carbon Monoxide Emissions. Alternatives controlling potential hydrocarbon and carbon monoxide emissions from oil shale processing facilities are shown in Figures 6-5 and 6-6, respectively. Tables 6-6 and 6-7 show advantages and disadvantages of hydrocarbon and carbon monoxide control options aplplicable to oil shale processes.

Perhaps the easiest method to control carbon monoxide and hydrocarbon emissions is complete fuel combustion by assuring the presence of sufficient oxygen during combustion, converting pollutants to carbon dioxide and water. Due to mine safety regulations, catalytic converters are required for all diesel equipment used in mining operations.

Vapor recovery processes for hydrocarbon emission controls could be used in situations where recovered hydrocarbons have high market value and where hydrocarbon concentration is high enough to make its recovery economically feasible.

Fugitive hydrocarbon emissions have two principal sources: leaks and evaporation from open surfaces. Unlike fugitive dust, which arises in a diffuse pattern over an area, many fugitive hydrocarbon losses occur from

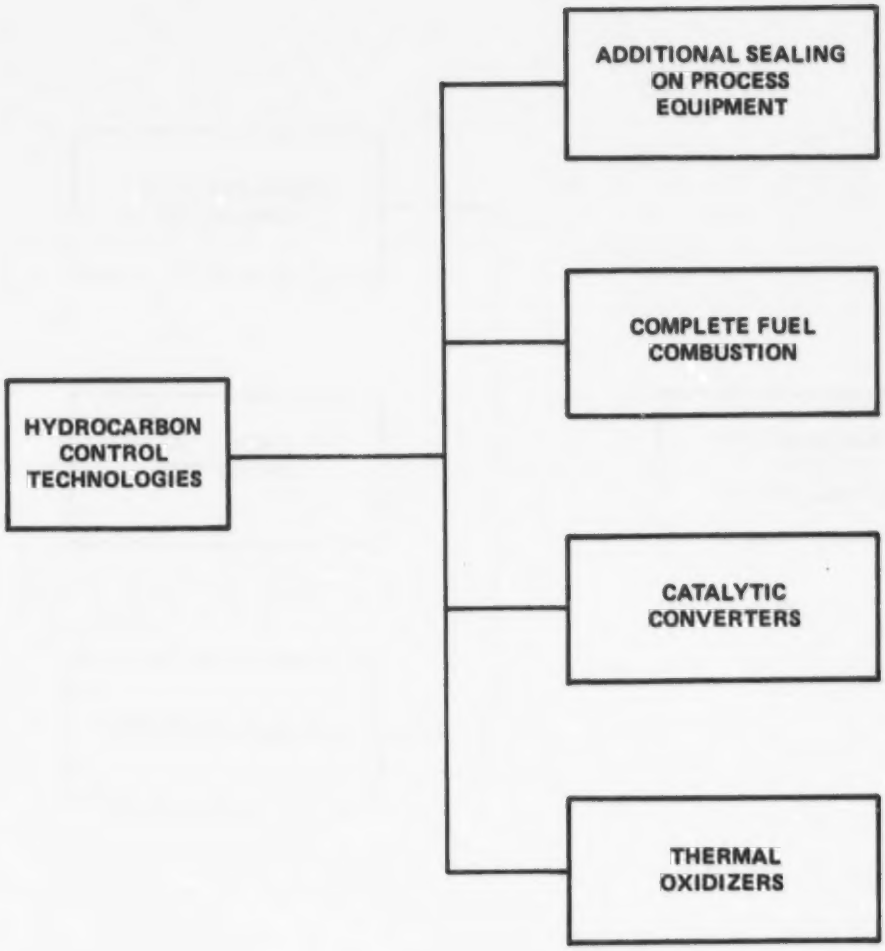

Figure 6-5. Hydrocarbon control technologies.

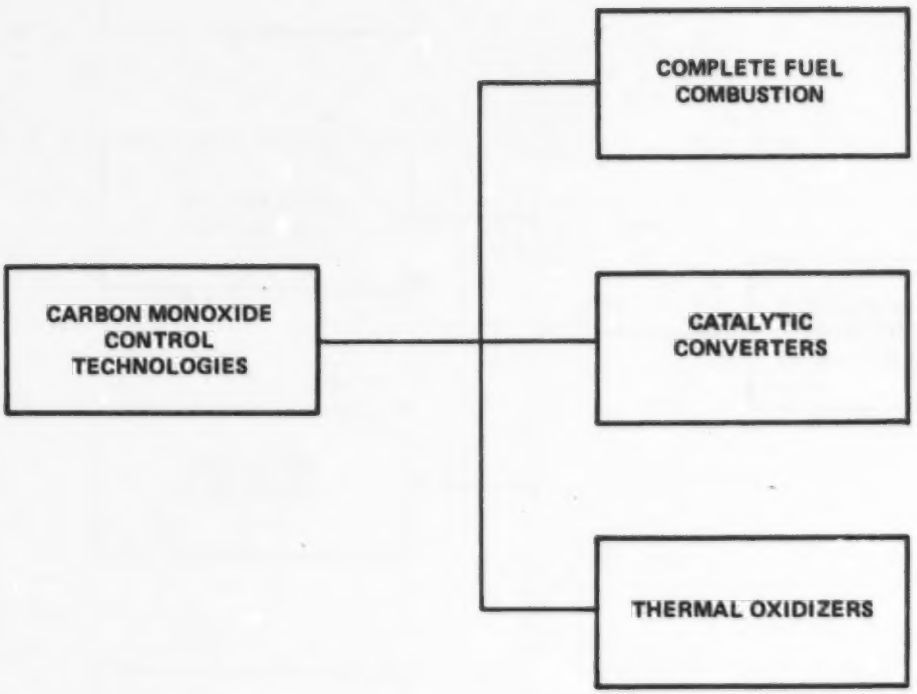

Figure 6-6. Carbon monoxide control technologies.

TABLE 6-6. KEY FEATURES OF HYDROCARBON CONTROL SYSTEMS APPLICABLE TO OIL SHALE PROCESSES[7]

Hydrocarbon control techniques	Operating principle	Performance	Advantages	Disadvantages
Additional sealing on process equipment	Includes double seals on pumps and other rotating machinery, closed loop sampling, caps on open ended valves, and periodic monitoring of equipment to find hydrocarbon leaks quickly.	About 60%-65% reduc-tion of fugitive hydrocarbon emissions is possible with this level of control.	Requires a small capital and operating cost and will probably more than pay for this cost due to the value of the hydrocarbons which are prevented from being emitted.	Should be implemented during new plant construction. Requires more capital investment to retrofit the controls of an existing plant.
Complete fuel combustion	Combustion process is operated with excess air to insure complete oxidation of all hydrocarbons to CO_2 and H_2O.	Can convert close to 100% of all hydrocarbons in the fuel to CO_2 and H_2O.	Eliminates the need for downstream equipment to complete the conversion of CO to CO_2.	Can increase NO_x for motion.
Catalytic converters	Hot exhaust gas is passed over a catalyst where the unburned hydrocarbons are reacted with the excess air in the exhaust gas and are converted to CO_2 and H_2O.	Can convert up to 80% of the hydrocarbons in diesel exhaust gas streams to CO_2 and H_2O, for other fuel burning processes up to 99% conversion is possible.	Does not require any fuel and has no moving parts so that routine maintenance is minimal.	The catalyst, which is expensive, must be replaced periodically.
Thermal oxidizers	Waste gas streams containing unburned hydrocarbons are burned with excess air and additional fuel if needed to completely oxidize all hydrocarbons to CO_2 and H_2O.	Can convert close to 100% of all hydrocarbons in the gas stream to CO_2 and H_2O.	Will insure complete oxidation of hydrocarbons.	Can have a high energy requirement when supplemental fuel is used.

TABLE 6-7. KEY FEATURES OF CARBON MONOXIDE CONTROL SYSTEMS APPLICABLE TO OIL SHALE PROCESSES[7]

Hydrocarbon control techniques	Operating principle	Performance	Advantages	Disadvantages
Complete fuel combustion	Combustion process is operated with excess air to insure complete oxidation of all hydrocarbons to CO_2 and H_2O.	Can convert close to 100% of all hydrocarbons in the fuel to CO_2 and H_2O.	Eliminates the need for downstream equipment to complete the conversion of CO to CO_2.	Can increase NO_X for motion.
Catalytic converters	Hot exhaust gas is passec over a catalyst where the unburned hydrocarbons are reacted with the excess air in the exhaust gas and are converted to CO_2 and H_2O.	Can convert up to 80% of the hydrocarbons in diesel exhaust gas streams to CO_2 and H_2O, for other fuel burning processes up to 99% conversion is possible.	Does not require any fuel and has no moving parts so that routine maintenance is minimal.	The catalyst, which is expensive, must be replaced periodically.
Thermal oxidizers	Waste gas streams containing unburned hydrocarbons are burned with excess air and additional fuel if needed to completely oxidize all hydrocarbons to CO_2 and H_2O.	Can convert close to 100% of all hydrocarbons in the gas stream to CO_2 and H_2O.	Will insure complete oxidation of hydrocarbons.	Can have a high energy requirement when supplemental fuel is used.

specific points, such as valves, flanges, drains, pump seals, compressor seals, and drains. Figitive emission controls are primarily based on good plant design and maintenance procedures rather than on equipment. Plant design items to help reduce fugitive emissions include the following:

- Confinement, diversion, and flaring
- Dual seals on pumps and other moving equipment
- Sparing of critical pumps, compressors, and valves
- Use of double-sealed floating roof storage tanks.

Probably the most important item in preventing fugitive emissions is good preventative maintenance, which includes using outages and normal downtimes for repairs and testing potential fugitive emission sources on a systematic basis.[8]

6.3 AVAILABLE CONTROL OPTIONS FOR EMISSION REDUCTION

Presently there are no commercial-scale oil shale processing facilities on stream, although a number of facilities are planned or just beginning commercial development of processing sites. The processes being developed have not been fully characterized as to type and quantities of pollutants likely generated by commercial operations that optimize shale production and environmental tradeoffs.

Present strategies for controlling potential pollutant emissions are in the conceptual stage. However, there are a number of efficient control technologies available that could find application. In fact, high removal levels are possible for criteria pollutants. Details of these processes are given in Subsection 6.2.

Although controlling potential pollutant emissions from oil shale processing facilities may be feasible with present control technology, answers must be supplied to questions that have not been raised nor anticipated at present. Also, as pointed out in Section 6.2, interactions among the control techniques used at a single site may be beneficial or detrimental to the overall process. The design of control options must take into account these complexities, as well as the specifics of the retorting process, use of natural resources, and economics.

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